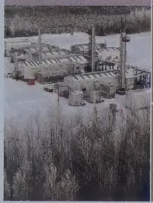

Anderson Exploration Ltd.

1998 Annual Report

ANDERSON
EXPLORATION LTD.

ABOUT THE COMPANY

Anderson Exploration Ltd. is a Calgary based senior oil and gas producer. The Company evolved from a program of oil and gas exploration, acquisition and development commenced by Mr. J. C. Anderson in 1968. Anderson Exploration became a public company in 1988. The common shares of Anderson Exploration are widely held and trade on The Toronto Stock Exchange under the symbol AXL. Anderson Exploration has a large oil and gas reserve base and operates approximately 80 percent of its production. The Company operates exclusively in western Canada. The Company is leveraged to the North American natural gas market with about 60 percent of its production and revenues made up of natural gas. Anderson Exploration operates and is a 50 percent owner of Federated Pipe Lines Ltd. which transports crude oil and NGL through extensive pipeline systems in Alberta and British Columbia. The Company has an experienced group of dedicated people pursuing an excellent inventory of exploration, development and acquisition projects.

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ABBREVIATIONS USED IN ANNUAL REPORT

API	American Petroleum Institute
Bbl	barrels
Bcf	billion cubic feet
Bpd	barrels per day
Mbbls	thousand barrels
Mcf	thousand cubic feet
Mcfd	thousand cubic feet per day
Mmbbls	million barrels
Mmcfd	million cubic feet per day
NGL	natural gas liquids
Tcf	trillion cubic feet

ABOUT THE COVER

Construction of the Anderson Exploration operated North Cecil Gas Plant, a new facility with a capacity of 38 million cubic feet per day, was completed in 1998. The facility, located about 85 miles north of Grande Prairie, Alberta, came on stream on April 27, 1998, nearly 10 years after the Company's first gas discovery in the immediate area.

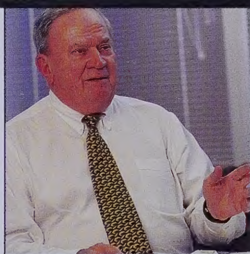
ANNUAL GENERAL AND SPECIAL MEETING

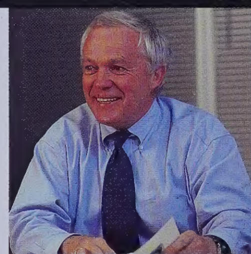
The Annual General and Special Meeting of Shareholders will be held on Wednesday, February 10, 1999 at 3:00 p.m. at the Westin Hotel, Calgary, Alberta.

1 Highlights

	1998	1997	% Change
Financial			
(in thousands, except per share amounts)			
Total revenue	$ 683,661	$ 750,047	(9)
Revenue, net of royalties	$ 575,945	$ 629,656	(9)
Cash flow from operations	$ 306,037	$ 383,045	(20)
Per common share	$ 2.49	$ 3.14	(21)
Earnings	$ 24,606	$ 87,943	(72)
Per common share	$ 0.20	$ 0.72	(72)
Average shares outstanding	122,794	121,873	1
Net capital expenditures	$ 527,658	$ 468,744	13
Long term debt	$ 695,517	$ 544,982	28
Shareholders' equity	$ 1,022,716	$ 986,071	4
Operating			
Daily sales			
Natural gas (Mmcfd)	555	549	1
Crude oil (Bpd)	29,808	27,472	9
NGL (Bpd)	7,376	5,669	30
Total liquids (Bpd)	37,184	33,141	12
Average prices			
Natural gas ($/Mcf)	$ 1.94	$ 1.91	2
Crude oil ($/Bbl)	$ 18.53	$ 25.46	(27)
Natural gas liquids ($/Bbl)	$ 16.61	$ 25.33	(34)
Total liquids ($/Bbl)	$ 18.15	$ 25.43	(29)
Reserves			
Natural gas (Bcf)			
Proven	1,758	1,768	(1)
Proven plus probable	2,675	2,713	(1)
Crude oil and NGL (Mbbls)			
Proven	148,047	130,907	13
Proven plus probable	225,570	200,323	13
Undeveloped land (thousands of acres)			
Gross (western provinces)	4,059	4,396	(8)
Net (western provinces)	3,183	3,421	(7)
Average working interest (%)	78	78	–
Drilling activity			
(gross number of wells drilled in Canada)			
Gas wells	237	195	22
Oil wells	138	356	(61)
Dry holes	71	118	(40)
	446	669	(33)
Service wells	8	36	(78)
Total wells	454	705	(36)
Employees			
Calgary	390	347	12
Field	347	332	5

2 Management's Message





J.C. Anderson
Chairman &
Chief Executive Officer
(far left)

Larry Macdonald
President &
Chief Operating Officer

In 1998, we completed our 30th year in business, 20 years as a private enterprise and 10 as a public company. Our experience served us well in what evolved to be a rather difficult year. On a barrel equivalent basis, we increased our product sales by five percent, however, our realized commodity price was substantially lower than in 1997. Oil and NGL prices declined by 29 percent while gas prices increased two percent resulting in a 12 percent decline in our barrel equivalent commodity price in 1998. Prices at the beginning of the year were strong but deteriorated significantly throughout the year. We more than replaced our production, but at a higher finding and development cost than we like to see. Although the Company's earnings remained positive in 1998, cash flow from operations and earnings decreased compared to 1997. In 1999, our financial results and to some extent our operating results will be driven by commodity prices. The outlook for gas prices in 1999 and beyond is positive and the Company is fortunate to be leveraged more than 60 percent to gas based on current sales volumes.

1998 IN REVIEW

During 1998, oil and NGL sales increased 12 percent to 37,184 barrels per day. Major contributors to the increase were the acquisition of an additional interest in Swan Hills, successful workover programs at Swan Hills and northeast British Columbia and successful drilling programs in Saskatchewan. These increases were partially offset by the sale, in late 1997, of the Company's Argentina operation which was producing about 1,570 barrels of oil per day, the shut in of some heavy oil production due to low prices and the temporary shut in of production as a result of forest fires in northern Alberta in the third quarter of the year.

Natural gas sales in 1998 increased modestly to 555 million cubic feet per day from 549 million cubic feet per day in 1997. New gas production came on stream in several areas, most notably in northeast British Columbia and the Peace River Arch in Alberta.

Natural gas prices increased slightly to $1.94 from $1.91 per thousand cubic feet. Oil prices declined 27 percent to $18.53 per barrel from $25.46 per barrel. NGL prices declined 34 percent to $16.61 per barrel from $25.33 per barrel. Therefore, notwithstanding the increase in product sales, cash flow from operations decreased 20 percent to $306 million or $2.49 per share and net earnings decreased 72 percent to $24.6 million or $0.20 per share. On a barrel equivalent basis, our total Canadian oil and gas revenue declined by $2.74 per barrel to $19.12 per barrel. Due to modest increases in operating costs, interest expense and current taxes, partially offset by declines in royalties and general and administrative expenditures, cash flow per barrel of oil equivalent declined by $2.92 per barrel to $8.76 per barrel. Earnings per barrel of oil equivalent declined to $0.53 per barrel from $2.36 per barrel, for a difference of $1.83 per barrel. Net capital expenditures in 1998 were $528 million versus $469 million in 1997. We spent the equivalent of 163 percent of our oil and gas cash flow from operations on oil and gas related activities and replaced 148 percent of our production with proven reserves before revisions at a unit finding and development cost of $8.84 per barrel equivalent on a proven basis and $7.41 per barrel equivalent on a proven plus one half probable basis, up from $7.92 and $6.49 per barrel respectively

1998 – Our 30th Year

Anderson Exploration Ltd. (AXL) has its roots in a modest oil and gas exploration, acquisition and development program started in August 1968 by J.C. Anderson – the Anderson Program. In its 20 year private phase, Program activities were funded by seven individual investors and one public corporation on a joint venture working interest basis and by two public corporations on a private company share equity basis. In 1998, the Company completed its 30th year in business, its 15th year in its present corporate form and its 10th year as a public company. The time line below and on the following pages in this report sets out some highlights of Anderson Exploration's history. It is a story of discovery, a number of unique deals, prudent financial management and concern for the interests of Program participants and shareholders. This has facilitated the growth of the Company to its present day stature as a leader in our industry.

Anderson Program is started by J.C. Anderson in 1968. AXL is formed as an operating company. Texas investors commit initial seed capital of $400,000. First well discovers East Bellis gas field.

Rosario Resources (NYSE) of New York joins Program in 1969 and forms Alamo Petroleum. Initial cash investment of $2 million. Becomes a joint venture participant for 11 years.

In 1970, Alamo funds purchase of three shut in gas wells drilled in the early 50's and 7,000 acres of leases at Belloy for $462,000. Cumulative gas production from these leases to date is 51 Bcf.

in 1997. Anderson Exploration's long term debt to cash flow ratio increased to 2.3 from 1.4. At the beginning of the year, we expected an increase but not of that magnitude. A heavy capital spending program early in the year and the sudden collapse in oil prices caused the higher than anticipated increase.

1999 CAPITAL BUDGET

In August 1998, the Company established a fiscal 1999 capital budget of $360 million with emphasis on expenditures for gas projects. In a budget review in November, the capital budget was reduced to $345 million. Subsequent to the November review, and because of continued deterioration in oil prices, we have now elected to defer work on nearly all of our oil related projects. Most of these projects can be pursued in the summer months and will be pursued then, if oil prices improve substantially. The Company's goal in its budget process in 1999 is to keep expenditures within cash flow in order to keep the balance sheet relatively strong.

PEOPLE

Two members of our Board of Directors have elected to retire. Noel Cleland and Jack Morrish will not be standing for election at our annual meeting in February 1999. We thank them for their advice and counsel during their tenure on the Board of Anderson Exploration. Art Williamson, Vice President, Drilling, retired after 16 years of dedicated service to the Company and several years of work as a consultant to Anderson Exploration prior to joining the Company. We wish these gentlemen the very best in whatever they undertake in the future.

INDUSTRY CONDITIONS

Notwithstanding the precipitous drop in oil prices which began over a year ago, the industry continued to spend heavily through the winter months and beyond. The result has been an increase in leverage on balance sheets to the point that additional debt financing is generally not possible or sensible. Financing by the sale of share equity is not an alternative in the present investment climate. Because of low oil prices, cash flows are down as well. Industry field activity has dropped off considerably and will continue to drop. The current winter months will attract a higher level of activity but not as high as a year ago. The costs for the goods and services we use have declined and should continue to do so. There is a desire on the part of many to shift spending emphasis from oil to gas but because of high debt, lack of equity funding and depressed cash flows, a meaningful shift is probably not possible from an industry perspective. This contributes to the positive outlook for gas prices in Canada.

OUTLOOK

Crude oil prices are the wild card for 1999 but, in our opinion, the outlook for meaningful increases from present levels is not good. About a year ago, those countries in OPEC with excess production capacity, notably Saudi Arabia, Kuwait and the UAE, increased production to protect market share in the face of falling demand in Asia. As a result, oil prices crashed. These countries and some others, namely Mexico, Norway and Venezuela, subsequently agreed to production cuts in order to strengthen prices. Although some cuts have been made, they have not materialized to the extent agreed nor does it appear that they will. The period of low oil prices has prevailed long enough for some oil exploration and

Peace River Arch area gas purchase contract is negotiated with California buyer in 1970 containing an interest free development loan commitment of 1¢/Mcf for gas discovered.

Discover Dunvegan Gas Field on Peace River Arch in September 1970. Proven gas reserves of over one Tcf are developed.

Program receives first production revenue in late 1972. Final advance on total $11.2 million interest free development loan received from gas purchaser. Substantiates discovery of 1.12 Tcf of gas.

Dunvegan Field unitized and production commences in January 1973. AXL now operates with 51.6% interest. Total field cumulative production at September 30, 1998 is 880 Bcf of gas.

development projects in the non-OPEC world to begin to fall off the table as being uneconomic. Questions need to be asked, such as "Is the North Sea economic on balance at $US10 per barrel Brent?" and "Is the oil side of the business in North America economic on balance at $US11 per barrel WTI?". To be sure, some individual oil projects are economic, but most are not, making some producing regions in the world uneconomic at present prices. As the decline in production in the non-OPEC world approaches the excess production volumes in the overproducing OPEC countries, oil prices will recover, but not in the short term. It is interesting that Kuwait and Saudi Arabia have recently invited western oil companies to help develop methods of assisting them in increasing their own delivery capacity, however, not on an ownership basis, indicating some concern over their sustainable future capability. We expect relatively low oil prices to prevail throughout 1999.

In spite of the warm weather start to the 1998-1999 heating season, the outlook for Canadian natural gas prices is excellent. Our view on gas is set out on the pages immediately following this message. With the new export pipeline capacity now on stream, Canadian prices are free to approach equilibrium with higher prices in the U.S. marketplace. Canadian deliverability is now in balance with demand as a result of the additional take away capacity. The decline rates of present production are much higher than in the past. The industry's capacity to make up for decline and increase production is restricted by opportunity and the lack of financial capacity. All of this means higher gas prices, which we believe are sustainable for years to come.

Our leverage to gas should serve us well in 1999 and beyond. Our average liquids production in 1999 will decline from 1998 given our decision to defer or eliminate most spending on oil projects. We feel that restricting capital spending in the current economic climate represents the best application of our available resources at this time. Inevitably, opportunities surface in the downturns in our business and we want to be in a position to capitalize on them.

We take this opportunity to thank our people for their efforts in 1998 and express our confidence that they will deliver exemplary performance in what may not be the best of times in the coming year. Also, be assured that we appreciate the support of you, our shareholders.

J.C. Anderson

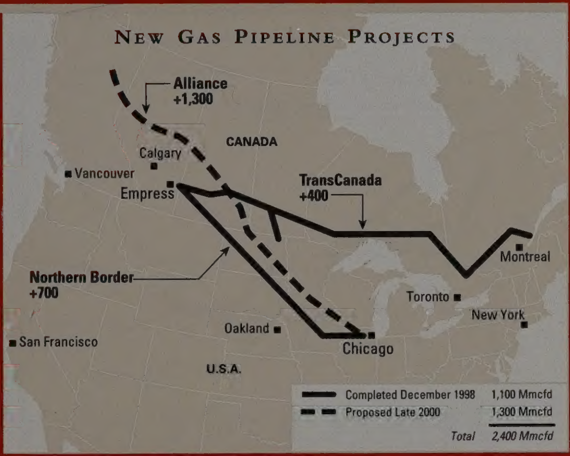
J.C. Anderson
Chairman & Chief Executive Officer

Larry Macdonald
President & Chief Operating Officer

December 28, 1998

3

1998 North America Natural Gas Review

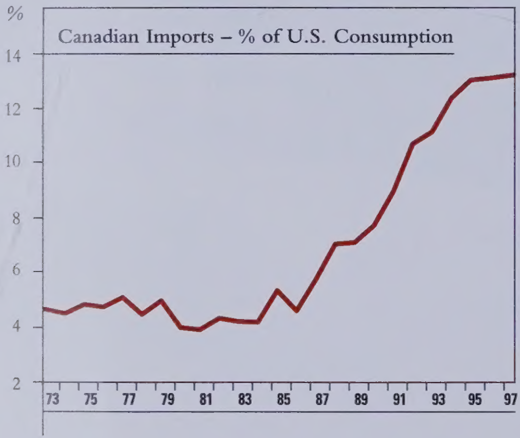


In our 1992 annual report, we addressed the fundamentals of the North American natural gas business as they existed at that time. Natural gas prices had declined drastically to their lowest levels in over a decade. We felt we could see the end of the free fall in prices based on a look at production, consumption and remaining reserve trends in the United States and Canada coupled with pipeline and drilling activity. We concluded that natural gas prices had bottomed and they would go up. They did. Our average price in 1992 was $1.33 per Mcf increasing to $1.67 and $1.98 in 1993 and 1994 respectively, before tipping over again in 1995.

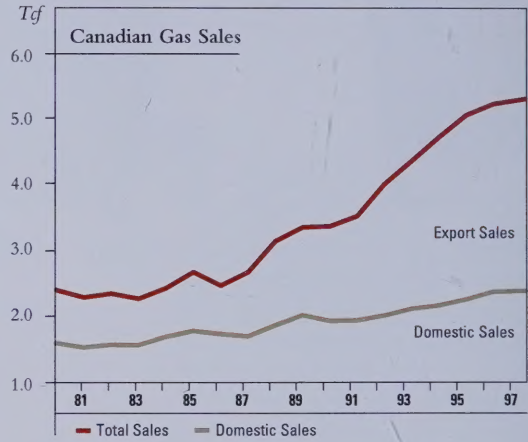
The basic fundamentals of the gas business in North America remain essentially the same as in 1992. Canadian production is still increasing and capturing a growing share of the very large U.S. market. The proportion of total Canadian production being exported is still increasing. U.S. demand continues to increase at a rate faster than indigenous production. New take away pipeline capacity from western Canada is coming on stream much the same as in 1992. Remaining gas reserves are still declining in both countries and Canada's reserve to production (R/P) ratio is declining from a very high level to approach that of the U.S. All of these fundamentals point to increasing gas prices for Canadian producers.

There are conditions which exist in the business today which have evolved in the past few years and will have a positive impact on gas pricing in the future. In 1992, the industry was still labouring through the process of deregulation and was coming out of an era where daily gas sales were backed by long life reserves under reserve based sales contracts. This resulted in production at less than capacity creating excess deliverability in the system relative to demand. There were many opportunities to ramp up gas production in the existing fields which came out from under the constraints imposed by long term contracts. In Canada, deliverability was easily increased to substantially exceed pipeline take away capacity and as a result, prices declined again. In the U.S., deliverability enhancement opportunities were also underway. Examples were increased drilling on the shelf in the Gulf of Mexico and coal seam gas development in the San Juan Basin. Today in Canada, with the development work which has taken place in the recent past and new pipeline infrastructure, the industry is producing at capacity. The result is that existing production is exhibiting a high decline rate with much lower R/P ratios. Since most relatively easy deliverability enhancement work has been done, decline replacement and production increases must be generated from new supply. Supply and demand have come into balance and are likely to stay that way well into the future. Therefore, our conclusion is that the gas price increases we are and will be experiencing are also sustainable well into the future.

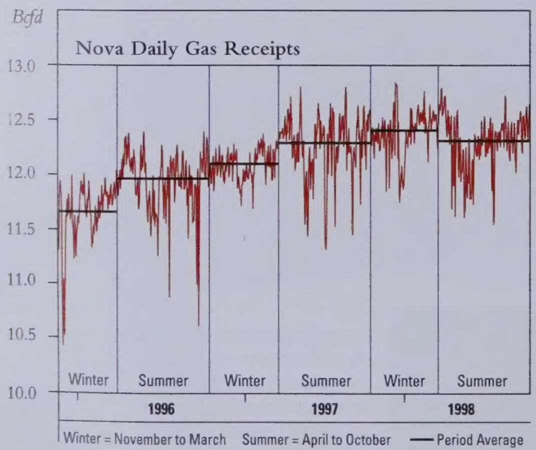
Keith Fardy
Manager,
Natural Gas Marketing



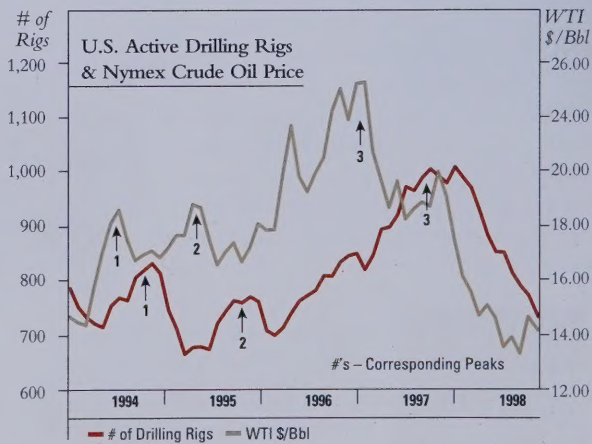
Canadian imports now supply over 13% of U.S. consumption compared to 4 to 5% up until the mid 80's. Current new pipeline capacity will cover an additional 1.8% of U.S. consumption, about equal to the anticipated increase in demand in 1999.



Since 1992, Canadian gas sales have increased substantially. About one third of today's delivery capacity has been added in this period. Domestic sales increased only 23% but export sales increased 84%. About 55% of Canada's sales are exported to the U.S. and this will increase with new pipeline capacity being brought on stream.



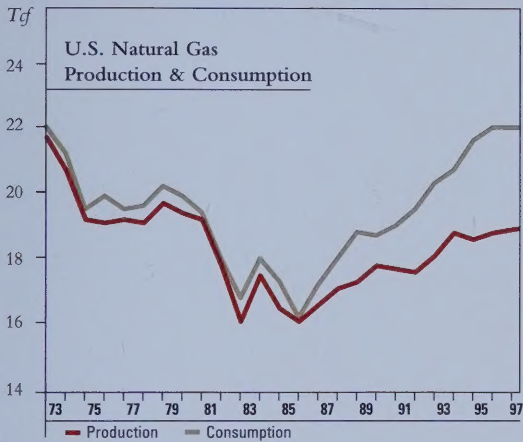
Recent Nova field receipts provide another indication of the high decline rates now built into the system. Summer 1998 receipts increased only slightly over summer 1997 receipts even though new production was added. Industry's ability to fill new pipeline capacity is questionable, placing upward pressure on prices.



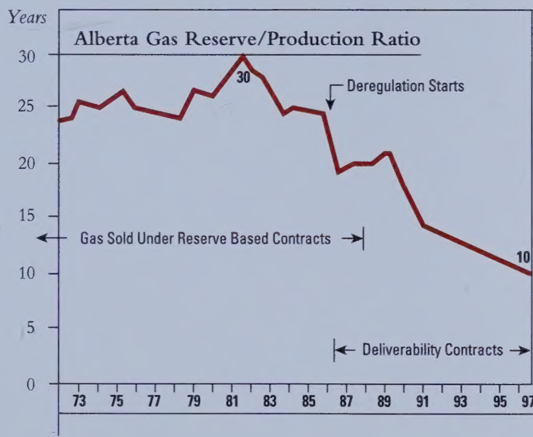
Drilling activity generally responds to crude oil prices. The peaks in drilling activity lag the peaks in oil prices by a few months. Gas rig activity responds to gas prices, but also to oil prices. In periods of very low oil prices, industry does not have sufficient cash flow to shift to gas activity, a situation which currently exists in Canada and the U.S.


Leslie Dimion
Senior Financial Accountant (left)

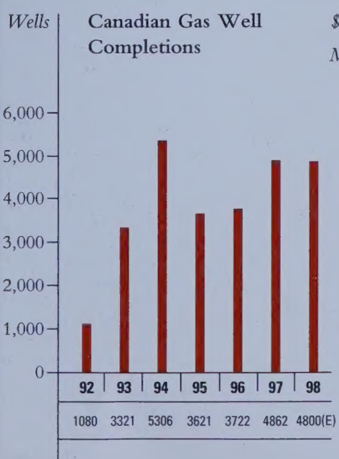
Allen Quon
Senior Information Systems Specialist



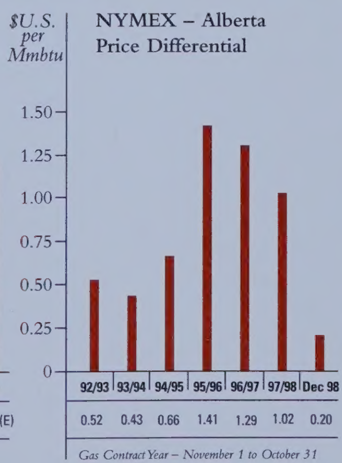
Since the mid 80's, U.S. gas consumption has increased at a rate much faster than production to the point that consumption exceeds domestic production by over 3 Tcf per year. Nearly all of that difference is made up by Canadian imports. Most of the future increases in demand will be met from Canada, but at higher prices for Canadian producers.



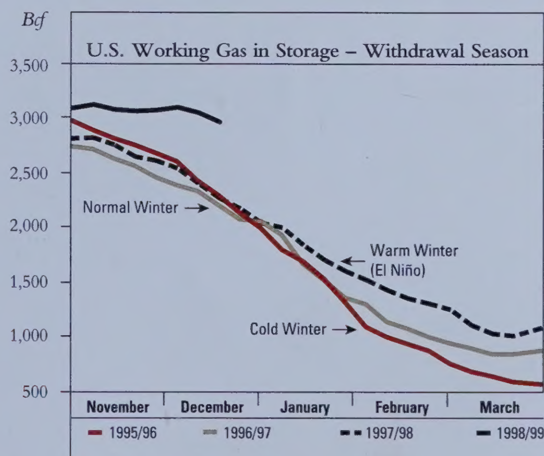
Alberta's R/P ratio has dropped dramatically. In the past, producers sold gas to pipelines under reserve based contracts with daily sales quantities backed by 20 to 25 years of supply. This excess deliverability is now gone. The Canadian industry is now producing at capacity with an R/P ratio similar to the U.S.



In the past, industry has responded to increasing gas prices by completing more gas wells. Now initial production per completion is lower and decline rates are much higher so more completions are necessary. Industry will not be able to ramp up production as easily as in the recent past by increasing well completions.



In the early 90's, 1.8 Bcfd of pipeline capacity was added to serve U.S. markets. By the mid 90's, Canadian deliverability again exceeded pipeline capacity. A significant price differential developed in favour of U.S. prices. With new pipeline capacity, the differential is dropping dramatically, resulting in higher Canadian prices.



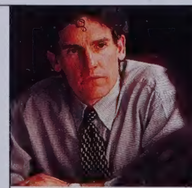
A short term wild card in the pricing scenario is gas storage. After the warmest year on record in 1998, storage levels two months into the withdrawal season are at record levels. Depending on the weather, this could have a depressing effect on U.S. gas prices but in the long term will not offset the effects of flat U.S. production and additional pipeline capacity from Canada.

4 North Cecil Gas Project

In the industry, gas projects often develop over long periods of time and with the involvement of a number of operators. In May 1988, Anderson Exploration drilled an oil prospect at North Cecil, about 85 miles north of Grande Prairie. The well was a gas discovery. Almost 10 years after drilling that discovery well, the Company's gas properties in the area came on production with completion of the North Cecil Gas Project. In the period between discovery and initial production, the Company and others periodically explored the area until sufficient gas reserves were finally developed to justify bringing pipeline infrastructure into the area. About two years ago, Anderson Exploration took the lead in promoting the construction of facilities to accommodate gas production. Successful implementation of the project capitalized on the talents of Company people from several disciplines and illustrates that Anderson Exploration has the "in house" expertise to pursue such projects from the initial exploration phase through to the operation of production.

Ron Newborn
Senior Landman

"In early 1988, we got a modest start at North Cecil by acquiring an interest in 1,920 acres on an oil prospect. We drilled a well which turned out to be a gas discovery. With the lack of gas infrastructure, our exploration was basically put on hold except for the occasional well. In 1996, we became active at Crown land sales and in drilling. We now have an interest in over 80,000 acres in the area through lands acquired at Crown sales and in the Home Oil deal."



Ron Lambie
Area Exploration Manager

"In 1988, the Company drilled six wells in the area on what was conceived as an oil prospect. The result was three dry holes and three gas discoveries. Because gas infrastructure was not yet available, we did only sporadic exploration until 1996 when we made a couple of discoveries on land from the Home Oil deal. The success of this drilling led to development of the gas production infrastructure. That, in turn, will prompt more exploration and development in the area."

Gene Romansky
Production Engineer

"In November 1997, construction of the gathering system commenced and the plant started in January 1998. The rated capacity of the plant is 38 million cubic feet per day. The gathering system consists of 44 miles of lines tieing in 34 wells. Total cost of the facilities was $22.7 million – seven percent under budget. Gas from some producing zones is slightly sour at about 100 parts per million so amine sweetening and incineration are included in the plant design, as well as inlet separation, compression, dehydration and condensate stabilization. The facilities came on stream on April 27, 1998, 10 years after our first discovery."

Shirley Leong
Property Accountant

"I handle production accounting and regulatory filings for North Cecil. Gross gas production is currently 38 million cubic feet per day. We have eight joint venture partners in the project and most take their product in kind. I provide sales volume splits to our partners and to pipelines on a monthly basis. I record the Company's share of revenue and royalties, analyze operating expenses and do all government reporting for royalty purposes. Anderson Exploration's share of sales from the plant is currently 15 million cubic feet per day."

Andy Potter
Exploitation Engineer

"In early 1997, we conceived plans to construct facilities for our North Cecil gas properties. Other companies had discovered gas reserves in the area, but since we were the dominant operator we solicited nominations for capacity in a new gas plant and gathering system. There are now nine owners in the plant with Anderson Exploration as operator with 32 percent. Applications were made to regulators for approval for construction and operation of the plant. Design of the facilities was completed "in house" and meetings were held with area residents to apprise them of the project. The plant will service about 100 billion cubic feet of gas reserves which currently exist in the area."

5 Operations Review

$11.2 million development loan is fully repaid in 1975. Discover Woking, Hines Creek and Dixonville fields in an exploration deal funded by a gas purchaser.

BC Sugar (TSE) of Vancouver becomes a Program participant in 1976. Fairweather Gas is formed and BC Sugar ultimately earns 60% interest in Fairweather by investing $15 million.

Fairweather "Canadianizes" a portion of Program in response to Foreign Investment Review Act (FIRA). Program participants sell properties within Program for $20 million in 1976

LAND

In 1998, Anderson Exploration's undeveloped land inventory in the western provinces decreased seven percent to 3,183,000 net acres largely due to expiries and drilling activity. The undeveloped land base is located 63 percent in Alberta, 19 percent in British Columbia, 17 percent in Saskatchewan and one percent in Manitoba. The average working interest in this land base is 78 percent, the same as in 1997.

Industry activity at Crown sales during 1998 was down compared to 1997. In the four western provinces for the year ending September 30, 1998, $899 million was spent by industry to acquire 11.3 million acres of petroleum and natural gas rights, excluding oil sands rights, compared to $1.3 billion for 16.3 million acres in the prior year. This represents a 30 percent reduction in both industry Crown sale expenditures and in total acreage sold. The average price paid per acre remained constant at approximately $80 per acre. The reduction in total activity can be attributed to the decline in the price of oil, however, in the gas prone areas of Alberta and British Columbia, where nearly all of the Company's Crown land expenditures were made, competition remained intense. The Company's total expenditures at Crown sales declined 39 percent from 1997, but the price paid per acre increased 22 percent. As a result, the Company purchased about half as much acreage as in 1997. In fiscal 1999, Anderson Exploration will continue to be an active but selective participant at Crown sales in support of its exploration and development programs.

SUMMARY OF UNDEVELOPED WORKING INTEREST LAND HOLDINGS

At September 30	*1998*		*1997*	
Thousands of Acres	*Gross*	*Net*	*Gross*	*Net*
Western Provinces	*4,059*	*3,183*	4,396	3,421
Other	*1,314*	*209*	1,323	210
Total	*5,373*	*3,392*	5,719	3,631

CROWN SALE LAND ACQUISITIONS

	1998	*1997*
Expenditures ($000s)	*$ 23,228*	$ 37,995
Net Acres Acquired	*205,464*	407,951
Price Per Acre	*$ 113*	$ 93

DRILLING

During 1998, Anderson Exploration participated in drilling 446 wells for oil and gas versus 669 in 1997. The average working interest in the wells was 63 percent versus 64 percent in 1997. Expenditures for the drilling, completion and recompletion of wells in Canada in 1998 were $212 million versus $183 million in 1997. A higher proportion of the Company's drilling activity was shifted to the deeper and, therefore, more expensive part of the basin. In 1998, 63 percent of wells cased for completion attempts were for gas versus 35 percent in 1997. Drilling for oil targets was de-emphasized in 1998 because of the significant drop in the price of that commodity. The Company expects that 1999 will also be an active year for gas drilling. The total number of wells drilled will be less than in 1998 as the Company continues to pursue targets in the deeper part of the basin.

View from a producing well site at Turner Valley where oilfield operations have been conducted for over 75 years. *(photo opposite page)*

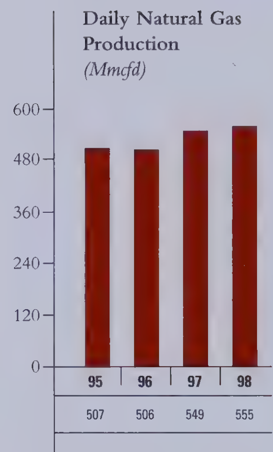
SUMMARY OF WELLS DRILLED

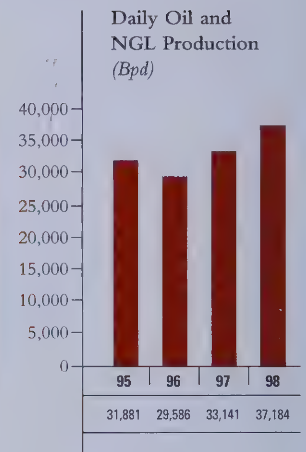
	1998		1997	
	Gross	*Net*	*Gross*	*Net*
Gas Wells	*237*	*149*	195	110
Oil Wells	*138*	*85*	356	232
Dry Holes	*71*	*46*	118	84
	446	*280*	669	426
Service Wells	*8*	*4*	36	12
Total Wells	*454*	*284*	705	438

CONSTRUCTION

In 1998, Anderson Exploration spent $109 million on the construction of field gathering systems and production facilities versus $123 million in 1997. The Peace River Arch area continued to be an area of high activity. The Dunvegan gas plant deep cut facility was modified to produce ethane. This project was made possible by the Federated Pipe Lines northern expansion which was also completed in 1998. It connected the Dunvegan facility to existing NGL sales pipelines. In April 1998, the North Cecil gas system commenced operation. It is designed to gather and process 38 million cubic feet per day of slightly sour gas. A sour gas plant was constructed at Normandville and is designed to handle 18 million cubic feet per day of slightly sour gas and re-inject acid gas. Seven shallow gas wells were tied into the Hines Creek field facilities to develop a new gas pool. At Belloy, eight new wells were tied in, bringing these facilities back to capacity. Additional compression will be added to Belloy in 1999, along with a pipeline under the Peace River to the Dunvegan gas plant. The boring of the river crossing was accomplished in 1998 at the same time as the Federated crossing on a shared cost basis. The crossing allows a production increase of seven million cubic feet per day and provides access to the high liquids recovery Dunvegan deep cut facility.

In Saskatchewan, a 3,000 barrels per day oil gathering system and battery was installed at Gainsborough and the Company's first gas facility in that province was installed at Edam. Five gas wells at Edam were tied into the plant which has a capacity of four million cubic feet per day. In a busy winter program in northeast British Columbia, nine wells were tied into the Wargen facility through an extensive gathering system and new gas wells were tied in across the Beatton River to the Birley Creek gas plant. This winter will bring further expansion of the gathering system and modifications to the plant compression at Wargen. Work will be completed on two compressor stations in the Eagle Field.





PRODUCTION/SALES

In 1998, Anderson Exploration's gas sales increased to 555 million cubic feet per day from 549 million cubic feet per day in 1997. The Dunvegan area replaced Leismer/Kirby as the Company's largest gas producing area, although both areas declined. These two areas combined contributed about 22 percent of the Company's total sales. Significant gains were made in the Birley/Wargen area in northeast British Columbia, where a combination of continued development work, the full year impact of the 1997 drilling and tie in program and a property acquisition resulted in a sales increase of 14 million cubic feet per day. At Woodenhouse in northeast Alberta, sales increased 32 percent as a result of well tie ins making it the Company's fourth ranking producing property. In the Yukon Territory, sales at Kotaneelee declined as one of the two producing wells was shut down for a period of time for repair and stimulation. Raw gas deliverability from that well was increased from 12 to 40 million cubic feet per day. Anderson Exploration is the operator

In the four year Fairweather funding period by BC Sugar, Fairweather participates in 327 Program wells. AMAX Inc. acquires Rosario and Alamo.

Bank line of credit of $280 million is arranged in 1981 for internal program acquisitions. Provides for first ever bank financing by Program.

In 1981, Fairweather acquires Alamo from AMAX for $177 million and individual Program participants sell properties within Program for $62 million. In 1982, individual participant sells shares within Program for $31 million.

In 1982, six Program companies amalgamate, placing all Program assets under AXL in the corporate form which exists today.

of this property with a 33 percent working interest. The impact of this successful work, as well as other work at Blackstone and Wapiti/Karr, will be seen in 1999.

Crude oil sales averaged 29,808 barrels per day in 1998, an increase of nine percent over the 1997 production. The acquisition of an additional interest in the Swan Hills Unit, combined with an aggressive program to expand the miscible flood and workover program, contributed significantly to the increase. Swan Hills remains the Company's largest oil property. A successful drilling and workover program in the Eagle and Stoddart fields in northeast British Columbia increased sales from these fields by 1,113 barrels per day over the average of 1997. Lloydminster heavy oil production increased 22 percent over 1997. Deteriorating heavy oil prices at mid year prompted the Company to shut in 2,000 barrels per day of production and severely curtail well workover and drilling programs. As well, some light oil work has been deferred because of the low commodity price.

DAILY AVERAGE NATURAL GAS SALES

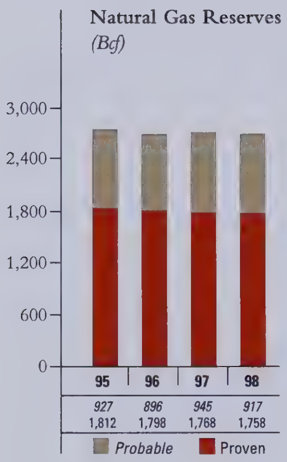
(Mcfd)	*1998*	*1997*
Dunvegan	***62,158***	67,297
Leismer/Kirby	***61,181***	69,720
Birley/Wargen	***32,330***	18,131
Woodenhouse	***19,459***	14,725
Ring Border	***16,721***	15,931
Belloy/Cindy	***16,564***	14,685
Hines Creek	***16,336***	13,996
Eaglesham/Culp	***15,261***	15,379
Blackstone	***14,847***	14,293
Pembina/Brazeau	***13,673***	9,067
Peggo/Pesh	***13,204***	14,306
Mistahae	***13,104***	12,789
Pica/Jack	***12,369***	15,705
Normandville	***12,358***	10,283
Harmattan	***11,928***	12,904
Saddle Hills	***11,644***	11,384
Marten Hills	***9,346***	9,189
Kotaneelee	***9,285***	10,096
Wapiti/Karr	***8,719***	11,032
Puskwaskau	***8,407***	7,399
Other & Royalty	***175,603***	180,811
Total	***554,497***	549,122

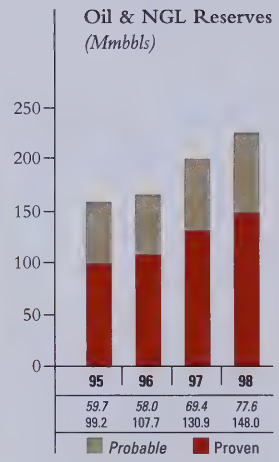
DAILY AVERAGE OIL & NGL SALES

(Bpd)	*1998*	*1997*
Oil		
Swan Hills	***5,707***	3,768
Lloydminster Heavy	***3,476***	2,846
Eagle	***2,912***	1,861
Hayter	***2,153***	2,435
Valhalla	***1,658***	1,882
Mitsue	***1,216***	1,524
Gainsborough	***1,127***	502
Innes	***1,095***	997
Stoddart	***1,057***	995
Pierson	***925***	965
Virginia Hills	***903***	957
Pembina/Brazeau	***882***	958
Cecil/Royce	***537***	529
Normandville	***509***	368
Progress	***473***	403
Genesee/Highvale	***469***	488
Harmattan	***405***	460
Woodriver/Bashaw	***383***	451
Turner Valley	***364***	357
Provost	***362***	289
Other	***3,195***	4,437
	29,808	27,472
NGL	***7,376***	5,669
Total	***37,184***	33,141

1998 QUARTERLY SALES

	Q1	*Q2*	*Q3*	*Q4*	*Year*
Gas (Mmcfd)	*561*	*554*	*545*	*558*	*555*
Oil (Bpd)	*30,700*	*31,062*	*29,046*	*28,441*	*29,808*
NGL (Bpd)	*6,529*	*8,731*	*6,948*	*7,320*	*7,376*
Liquids (Bpd)	*37,229*	*39,793*	*35,994*	*35,761*	*37,184*





RESERVES

In 1998, the Company replaced 148 percent of production with proven reserve additions, net of revisions, by spending 163 percent of cash flow from operations on capital expenditures. Before revisions, the Company added 244 billion cubic feet of proven gas reserves and 29.9 million barrels of oil and NGL with the drill bit and net property acquisitions. At year end, after revisions, proven natural gas reserves were down one percent over last year and proven oil and NGL reserves were up 13 percent over last year.

Before revisions, the Company's finding and development costs were $8.84 per barrel of oil equivalent for proven reserves and $7.41 per barrel of oil equivalent for proven plus one half probable reserves. The finding and development costs were based on oil and gas related capital expenditures of $480 million. Finding and development costs prior to revisions were 12 percent higher than 1997 due in part to the overheated cost environment that existed in industry for most of the Company's fiscal year. Some of these cost related pressures have subsided. On the gas side, the Company took a negative revision for proven reserves of 52 billion cubic feet and a negative proven plus probable revision of 158 billion cubic feet. The single largest revision was undertaken at the Company's Kahntah property in northeast British Columbia due to poor production performance coupled with disappointing results from the winter drilling program. The Kahntah reserves were reduced by 45 billion cubic feet of proven and 60 billion cubic feet of proven plus probable gas reserves. The Kahntah revision represents 87 percent of the proven gas revision and 38 percent of the proven plus probable gas revision. The remainder of the negative proven gas revision and a further 32 percent of the proven plus probable gas revision was due to the Company's detailed review of its miscellaneous properties. While revisions to proven reserves for oil and NGL were positive, the Company reduced its proven plus probable oil and NGL reserves by 4.3 million barrels due to performance issues at the outside operated Mitsue Unit and low oil prices associated with medium and heavy oil properties.

In 1998, the Company continued to be active in the property acquisition market. Anderson Exploration completed 25 property acquisition transactions at a total cost of $6.43 per barrel of oil equivalent for proven reserves and $5.44 per barrel of oil equivalent for proven plus one half probable reserves. The largest transaction was the acquisition of an additional 10.6 percent interest in the Company operated Swan Hills Unit No. 1 for $98.8 million at a cost of $6.44 per barrel of oil equivalent proven reserves and $5.49 per barrel of oil equivalent proven plus one half probable reserves. On the disposition side, the Company sold 21 properties for total proceeds of $24.2 million. The largest transaction was the sale of Anderson Exploration's interest in the Sandalta oil sands lease for $9.3 million. Dispositions, excluding the Sandalta proceeds, resulted in an average realization of $12.13 per barrel of oil equivalent for proven reserves and $8.35 per barrel of oil equivalent for proven plus one half probable reserves.

AXL completes private placement of common shares for $110 million in 1983. Kerr Addison Mines (TSE) of Toronto invests $80 million.

In 1988, AXL becomes public company when BC Sugar dividends one half of its AXL common shares to its shareholders. Major shareholders of AXL are Kerr Addison, BC Sugar and J.C. Anderson.

AXL acquires Columbia Gas Development of Canada for $106 million at a bottom in the natural gas market in 1992.

On November 1, 1993, after protracted negotiations, AXL receives a settlement payment of $25 million as compensation for termination of its California gas contract.

The Company's gas reserve life indices are 8.7 years on a proven reserve basis and 13.2 years on a proven plus probable reserve basis. The oil and NGL reserve life indices are 10.9 years for proven and 16.6 years for proven plus probable. In this fiscal year, an independent engineering consultant evaluated 42 percent of the Company's proven reserves with the balance being evaluated by Company engineering personnel. The Company's intention is to have a minimum of 25 percent of its reserves evaluated annually by independent consultants.

1998 RESERVE ADDITIONS & REVISIONS

	Proven	*Probable*	*Total*
Natural Gas (Bcf)			
Drilling	222	70	292
Property Acquisitions	26	12	38
Property Dispositions	(4)	(4)	(8)
Total Additions	244	78	322
Revisions	(52)	(106)	(158)
Sales	(202)	–	(202)
Total	(10)	(28)	(38)

	Proven	*Probable*	*Total*
Crude Oil & NGL (Mbbls)			
Drilling	14,107	8,078	22,185
Property Acquisitions	16,556	5,845	22,401
Property Dispositions	(759)	(743)	(1,502)
Total Additions	29,904	13,180	43,084
Revisions	808	(5,073)	(4,265)
Sales	(13,572)	–	(13,572)
Total	17,140	8,107	25,247

YEAR END RESERVES – COMPANY WORKING INTEREST

	Proven	*Probable*	*Total*
Natural Gas (Bcf)			
As at September 30, 1997	1,768	945	2,713
1998 Additions & Revisions	192	(28)	164
1998 Sales	(202)	–	(202)
As at September 30, 1998	1,758	917	2,675

	Proven	*Probable*	*Total*
Crude Oil & NGL (Mbbls)			
As at September 30, 1997	130,907	69,416	200,323
1998 Additions & Revisions	30,712	8,107	38,819
1998 Sales	(13,572)	–	(13,572)
As at September 30, 1998	148,047	77,523	225,570

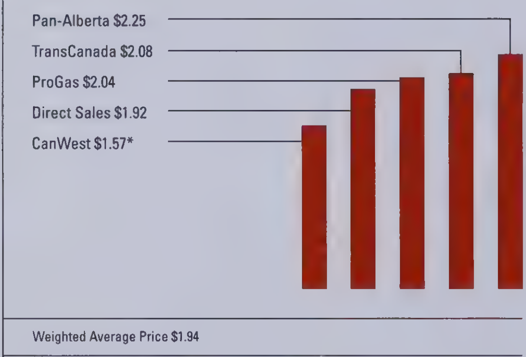
MARKETING AND PRODUCT PRICES

After a volatile year in 1997, natural gas prices stabilized somewhat in 1998. A modest price increase was experienced over 1997. Oil and NGL prices, on the other hand, declined precipitously. Early in the fiscal year, the OPEC countries with excess productive capacity increased production in the face of falling demand in Asia causing a downward pressure on prices which still persists.

Natural Gas

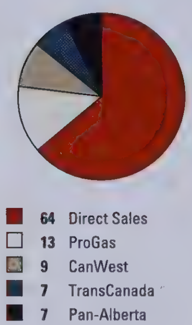
Anderson Exploration's average plant gate natural gas price increased modestly in 1998 to $1.94 per thousand cubic feet, marking the third consecutive annual increase. This performance exceeded expectations considering the warm winter and constrained export capacity out of western Canada. Total Alberta supply did not increase meaningfully in 1998. Consequently, provincial gas prices were stronger than expected, especially during the summer. Monthly average prices varied from a high of $2.28 per thousand cubic feet in November 1997 to a low of $1.79 in February and September 1998. During the year, 36 percent of the Company's gas volumes were sold to aggregators, such as ProGas, TransCanada,

1998 Gas Price
($/Mcf)



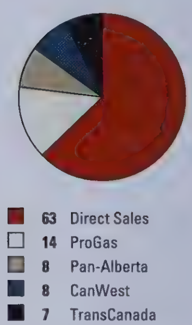
* *Gas price includes both wellhead and plantgate sales.*

1998 Gas Sales Distribution
(% of Volume)



Total Gas Sales = 202.4 Bcf

1998 Gas Revenue Distribution
(% of $)



Total Gas Revenue = $392.6 Million

Pan-Alberta and CanWest. For a marketing fee, aggregators gather supply from many producers and sell the gas to a variety of markets generally at indexed prices. The aggregator component of the Company's portfolio continues to decline. The balance of gas sales is marketed directly by the Company, predominantly within western Canada. Direct sales represented 64 percent of the total gas marketing portfolio, primarily made up of short term sales.

On June 30, 1998, two long term, fixed price co-generation contracts, with sales volumes of 21 million cubic feet per day, were terminated at the request of the natural gas purchasers. In return for ending the contracts, Anderson Exploration received settlement payments in the amount of $66.6 million dollars. Since the volumes are now available to take advantage of the recent increase in Alberta prices, these contracts were monetized at an opportune time.

Pursuant to the Company's long term marketing strategy, an increasing share of the portfolio, well over 70 percent, is tied directly to western Canadian prices. The outlook for future Canadian natural gas prices is bright with the solution to the problem of insufficient pipeline take away capacity at hand. In December, 1.1 billion cubic feet per day of additional export pipeline capacity will be added with the expansion of the TransCanada and Northern Border systems. The Alliance Pipeline project from northeast British Columbia to Chicago has now received regulatory approvals and, if built, will bring on an additional 1.3 billion cubic feet per day of capacity by late in the year 2000. The additional capacity creates an ideal situation for a producer such as Anderson Exploration, which now has the majority of its portfolio tied to the Alberta and British Columbia spot markets.

BC Sugar and Kerr Addison sell their AXL shares in 1992 and 1993 and AXL becomes a widely held company.

AXL acquires Amax Petroleum of Canada for $70 million in November 1993.

AXL acquires Home Oil Company Limited in September 1995 in a 100% share exchange transaction valued at $800 million, not including the assumption of $400 million in debt.

In 1997, AXL sells its operation in Argentina and its interest in an Australian company acquired through Home Oil for net proceeds of $55.7 million and an after tax gain of $7.8 million.

Crude Oil & NGL

The West Texas Intermediate (WTI) price for light sweet crude at Cushing, Oklahoma quoted on NYMEX is the benchmark for most crude oil prices in North America, including Edmonton, Alberta. The average price for WTI in fiscal 1998 declined 26 percent to $US16.18 per barrel from $US21.76 in 1997. The price received for Anderson Exploration's Canadian crude oil production, adjusted for exchange rate, quality and transportation, is based on the daily posted price at Edmonton, Alberta. In 1998, the Company's average price for its Canadian crude oil mix was $18.53 per barrel, down 27 percent from $25.37 in 1997. In 1998, 64 percent of the Company's Canadian crude oil was sold directly to U.S. and Canadian refiners with the balance sold to marketing intermediaries.

Approximately 20 percent of Anderson Exploration's total liquids sales are NGL. The Company sells its NGL as a mix or as individual components such as propane, butane and condensate. NGL prices generally track crude oil prices and they also declined substantially in 1998. The Company realized an average NGL price of $16.61 per barrel in 1998, a decrease of 34 percent compared to 1997. On average, condensate attracted a premium to crude oil prices in 1998 but the premium diminished throughout the year. In the first half of the year, condensate attracted a 37 percent premium to crude oil but in the fourth quarter, the premium was only three percent. This was due primarily to a decrease in demand for its use as diluent for transport of heavy oil, as producers shut in heavy oil production due to low prices.

1998 NGL STREAM

	Sales Volumes (Bpd)	*% of Stream*	*Price per Barrel*	*Decline in Price from 1997*
Ethane	703	10%	$ 7.38	14%
Propane	1,838	25%	11.67	49%
Butane	1,502	20%	12.17	33%
Condensate	3,333	45%	23.28	23%
Total	7,376	100%	$16.61	34%

HISTORICAL AVERAGE CANADIAN PRICES BEFORE HEDGING

Fiscal Year	*Gas $ per Mcf*	*Oil $ per barrel*
1985	2.82	33.76
1986	2.46	23.49
1987	1.87	21.65
1988	1.68	18.75
1989	1.65	18.49
1990	1.70	22.16
1991	1.52	24.19
1992	1.33	20.29
1993	1.67	20.66
1994	1.98	19.52
1995	1.43	22.05
1996	1.59	25.22
1997	1.91	25.37
1998	1.94	18.53

Straddle Plants

Anderson Exploration owns an average interest of 10.4 percent in two straddle plants located at Empress, Alberta. These plants are located on main gas transmission lines and process natural gas being exported from Alberta extracting NGL, primarily propane and butane, from the gas stream. Anderson Exploration processes its own gas at these plants plus a small amount of third party gas. The Company's share of the NGL produced from these facilities in 1998 was 1,808 barrels per day versus 1,827 barrels per day in 1997. These volumes are not included in the Company's reported sales volumes. Anderson Exploration profits from the difference between the value of the NGL extracted and sold as liquid and the additional value of the natural gas stream with higher heat content had these products been left in the stream. In 1997, high propane and butane prices relative to gas prices provided an excellent return on Anderson Exploration's investment in these facilities. In 1998, return declined substantially as a result of lower propane and butane prices and essentially flat gas prices, but still remained satisfactory.

No shares were issued when AXL became a public company in 1988. Since that time, AXL has gone to the public market on only three occasions issuing a total of 18 million shares for net proceeds of $198.5 million.

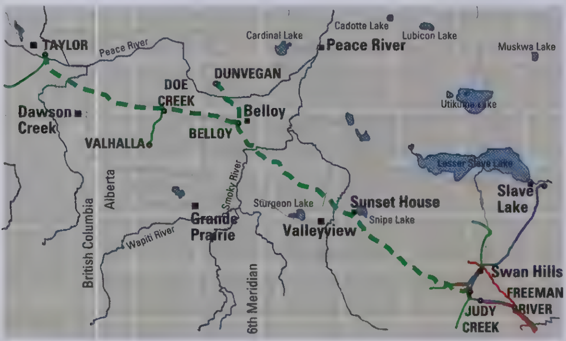
In its history, AXL has produced 1.27 Tcf of gas and 56.5 million barrels of oil and natural gas liquids for the benefit of Program participants and shareholders.

PIPELINE OPERATIONS

Anderson Exploration operates and is a 50 percent owner of Federated Pipe Lines Ltd. Federated's extensive pipeline system transports crude oil and NGL in Alberta and British Columbia. After the completion of an expansion project in 1998, Federated has about 2,000 miles of pipelines which have the capacity to move about 220,000 barrels of crude oil and 190,000 barrels of NGL per day. In 1998, throughput decreased marginally from 1997 to 231,000 barrels per day. The startup of the expansion increased throughput to 240,000 barrels per day by September 1998. Throughput is expected to increase to 250,000 barrels per day in fiscal 1999. Pipeline operations provide the Company with a reliable and steady stream of cash flow and earnings. In 1998, the pipeline contribution to Anderson Exploration's cash flow from operations and earnings was $9.7 million and $6.7 million, respectively.

FEDERATED PIPE LINES THROUGHPUT
(Bpd)

	1998	*1997*
Crude Oil	*151,000*	154,000
NGL	*80,000*	83,000
Total	*231,000*	237,000



Federated Northern Expansion

In August 1998, Federated entered a new era in its 40 year history with the completion of its northern expansion project. The expansion extends Federated's transportation capabilities into the prospective regions of northwest Alberta and northeast British Columbia. The new facilities include 280 miles of new pipelines, redeployment of 125 miles of existing pipelines and attendant pumping, storage facilities and truck terminals. The system is designed to batch natural gas liquids, segregated condensate and crude oil to markets in the Edmonton area. At Taylor, British Columbia, the system is tied into gas processing plants owned by others and a crude oil tank farm owned and operated by Federated. In northwest Alberta, the expansion is anchored by Anderson Exploration's Dunvegan gas plant. Approximately 65 percent of the initial expansion capacity of 60,000 barrels per day is now covered by term transportation agreements. With this major extension of Federated's transportation capabilities, Federated is strategically positioned for future growth in these new service areas when producing volumes economically justify the incremental investment.

The expansion supplements the existing Federated crude oil system in Alberta which transports oil from fields in the Swan Hills area to Edmonton refineries and export pipelines as well as a British Columbia pipeline which transports crude oil from Taylor to a refinery in Prince George and another pipeline at Kamloops. Additionally, it supplements the existing NGL system which moves NGL to industry facilities at Fort Saskatchewan, just east of Edmonton, from the Caroline gas plant north of Calgary and from liquids rich gas fields south and west of Edmonton. From Fort Saskatchewan, the original system transports ethane rich NGLs to the Swan Hills area for use in miscible floods in four major oil fields.

HEALTH, SAFETY AND ENVIRONMENT

Anderson Exploration is committed to protecting the health and safety of its employees and the public, as well as preserving the quality of the environment. Exemplary performance in the areas of health, safety and the environment is essential to fulfilling business goals and meeting the expectations of the Company's stakeholders.

Alex Bolton
Environmental Specialist (far left)

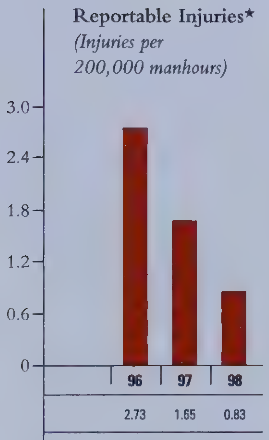
Ron Laycraft
Reeve of Municipal District of Foothills

Health and Safety

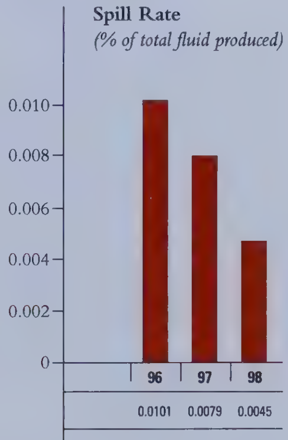
In 1998, Anderson Exploration's reportable injury frequency rate decreased by 50 percent following a 40 percent decrease in 1997. During the year, the Company implemented a Task Competency training program for field operating staff. This program and other initiatives have helped achieve these significant improvements. In 1998, Anderson Exploration became a member of the 'Partnerships' program spearheaded by Alberta Labour. This program plays a vital role in improving the overall safety performance of the oil and gas industry. In addition, the Company continues to prepare and implement emergency response plans for critical production, pipeline and drilling operations.

Environment

Anderson Exploration supports and participates in the Voluntary Climate Change Challenge and Registry (VCR) program as part of Canada's effort to address potential climate change. This voluntary approach encourages information sharing, cooperation and technology transfer within the industry. New technologies are being explored and modifications are being made to current practices to minimize emissions. The Company's goal is to reduce emissions.



* Includes both lost time and medical aid injuries.



The Company now has three acid gas injection facilities operating in the Peace River Arch, eliminating the need for gas flaring at these sour gas processing facilities. Efforts are underway to reduce emissions from glycol dehydrators throughout the Company. In 1998, Anderson Exploration produced approximately 178 million barrels of oil, NGL and water from its operated wells. The number of spills and the volumes spilled were reduced by over 40 percent compared to last year. The number of incidents decreased due to stringent application of programs targeted at improving equipment integrity as well as an ongoing emphasis on incident investigation and follow-up.

In fiscal 1998, Anderson Exploration spent over $6 million to abandon and reclaim inactive sites and address the impact of past operations at current production facilities. In addition, Anderson Exploration completed the first full year of operation of its Soil Treatment Facility in the Turner Valley area. This centralized site provides a cost effective method for treating and recycling soil at Turner Valley.

In keeping with the commitment to environmental responsibility, Anderson Exploration is taking a lead role in the advancement of research and technology development through participation in the Petroleum Technology Alliance of Canada (PTAC). During 1998, Anderson Exploration representatives served on the PTAC Board of Directors, as Chair of the recently established Environmental Research and Development Subcommittee and on a number of project technical steering committees. In addition, Anderson Exploration staff facilitated an industry/government workshop session on soil clean up standards that has led to the development of a joint three year, $700,000 research project to develop scientifically defensible, effects-based clean up standards for residual hydrocarbons in soil.

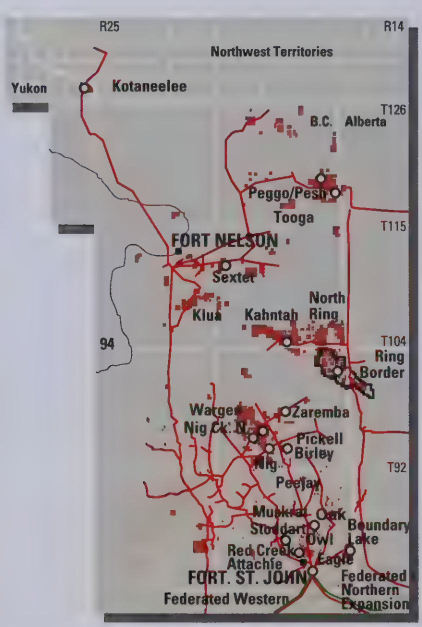
Comprehensive safety and environmental audits are completed on selected production and pipeline facilities each year. Action plans are prepared and implemented to address any concerns identified. Anderson Exploration will continue its efforts to ensure that the health, safety and environmental issues related to operations are well managed and that the Company remains in compliance with applicable safety and environmental laws and regulations.

6 Property Review

Substantially all of Anderson Exploration's operations are conducted in seven areas within western Canada. These seven areas stretch from the southeast tip of the Yukon Territory to Manitoba. They present the opportunity to participate in most types of geological plays and produce all types of hydrocarbons. The types of plays vary from complex foothills thrust belt structures along the mountains from southern Alberta to the Yukon Territories to relatively simple shallow gas and heavy oil plays in northeast Alberta and southeast Saskatchewan and Manitoba. The Company owns and operates significant surface facility infrastructure in all of these areas.

In fiscal 1998, over 95 percent of Anderson Exploration's sales came from these seven regions. About 78 percent of the Company's undeveloped land inventory in western Canada is located in these areas and 98 percent of the Company's 1998 drilling activity was conducted here.

NE British Columbia/Yukon



Tony Cadrin
Exploration Geologist

"Our 1998 workover and drilling programs in the Eagle and Stoddart fields increased oil production by an average of over 1,100 barrels per day for the year."

1998 Activity & Results

- Sales – 99 Mmcfd and 5,883 Bpd
- Acquired 18,000 net undeveloped acres
- Hold 580,000 net undeveloped acres in region
- Drilled 92 gross (72 net) wells, resulting in 55 gas, 19 oil and 18 dry
- Federated expansion into British Columbia from Alberta completed

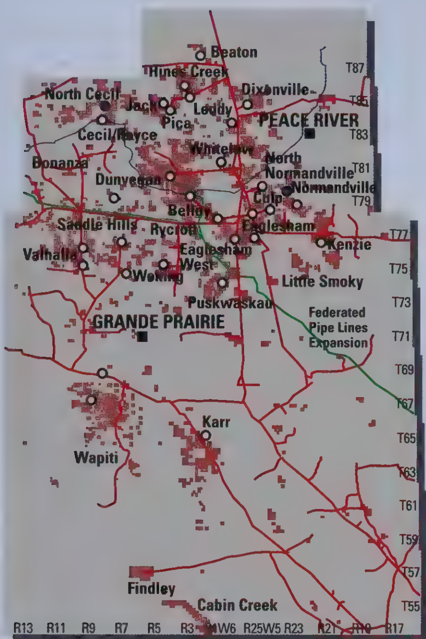
1999 Planned Activity

- Drill 25 gross (23 net) exploration wells and 26 gross (6 net) development wells
- New exploration drilling in Tooga

AXL Land — Gas Pipelines

Co. Interest Gas Plant — Federated Pipelines Expansion

Peace River Arch



Shana O'Neill

Facilities Engineer

"My major project in 1998 was work on the modification of the Dunvegan Gas Plant to permit ethane extraction from the gas stream."

1998 Activity & Results

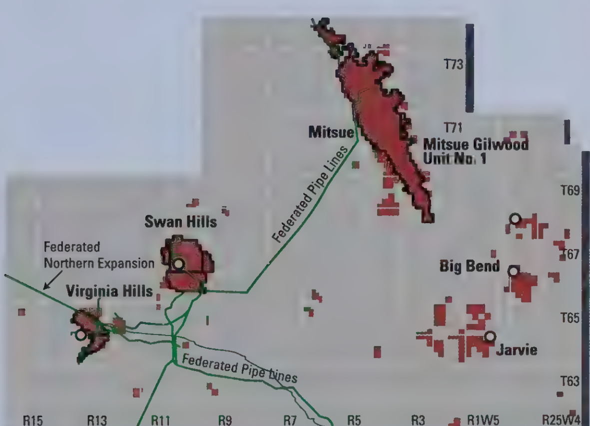
- Sales – 199 Mmcfd and 6,816 Bpd
- Acquired 93,574 net undeveloped acres
- Hold 893,700 net undeveloped acres in region
- Drilled 137 gross (86 net) wells, resulting in 87 gas, 28 oil, 19 dry and 3 service
- Constructed gas plants at North Cecil (38 Mmcfd) and Normandville (18 Mmcfd)
- Dunvegan Gas Plant modified for ethane extraction and pipeline connected by Federated expansion

1999 Planned Activity

- Drill 38 gross (31 net) exploration wells and 50 gross (26 net) development wells
- Complete the Peace River crossing permitting Belloy gas to be processed at Dunvegan increasing production and NGL yield
- Tie in of foothills gas production at Findley

AXL Land
Co. Interest Gas Plant
New Gas Plant – 1998
Gas Pipelines
Federated Pipelines Expansion

Swan Hills/Mitsue



1998 Activity & Results

- Sales – 11 Mmcfd and 8,635 Bpd
- Hold 29,400 net undeveloped acres in region
- Drilled 26 gross (7 net) wells, resulting in 5 gas, 15 oil, 4 dry and 2 service
- Acquired additional 10.6 percent working interest in Swan Hills Unit No. 1
- Completed tie in of the Federated expansion

1999 Planned Activity

- Tie in 3 gas wells in Big Bend
- Potential for substantial activity in this area, however, as it is largely an oil producing area, capital programs will probably be deferred due to low oil prices

AXL Land
Co. Interest Gas Plant
Oil Pipelines

Central and SW Alberta

Carl Hiscock
Manager, Drilling

"Although drilling activity in 1998 was down from 1997, it was the second most active year in our history and more wells were drilled in the deeper part of the basin."

1998 Activity & Results

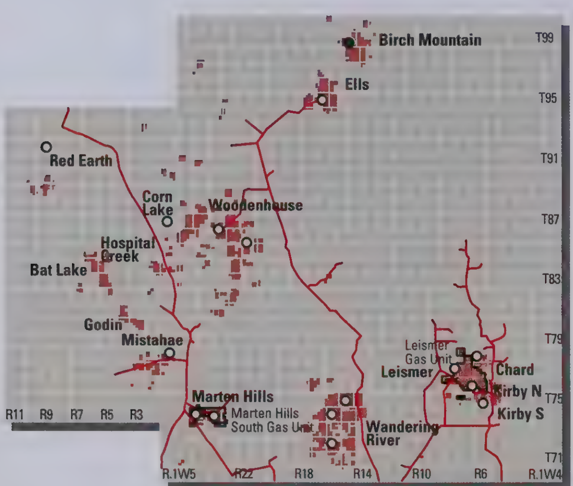
- Sales – 64 Mmcfd and 4,480 Bpd
- Acquired 29,788 net undeveloped acres
- Hold 92,600 net undeveloped acres in region
- Drilled 51 gross (16 net) wells, resulting in 26 gas, 16 oil, 8 dry and 1 service
- Participated in drilling a 75 Mmcfd (10 Mmcfd net) gas well at Blackstone
- Participated in construction of 38 mile Stolberg Pipeline
- Participated in 23 Mmcfd sweet gas plant at Pembina

1999 Planned Activity

- Drill 13 gross (9 net) exploration wells and 3 gross (2 net) development wells

AXL Land
Co. Interest Gas Plant
New Gas Plant – 1998
Gas Pipelines
Oil Pipelines

NE Alberta



1998 Activity & Results

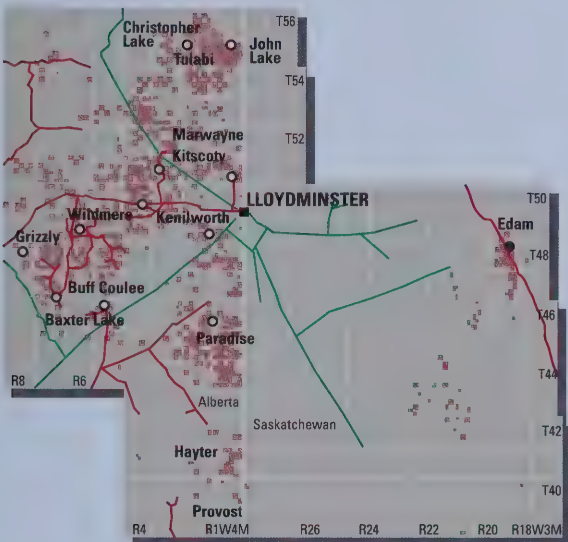
- Sales – 118 Mmcfd
- Acquired 40,980 net undeveloped acres
- Hold 434,000 net undeveloped acres in region
- Drilled 48 gross (33 net) wells, resulting in 43 gas, 3 dry and 2 service
- Continued well tie in program at Hospital Creek, Leismer, Kirby, Marten Hills, Red Earth, Wandering River and Woodenhouse

1999 Planned Activity

- Drill 22 gross (21 net) exploration wells and 17 gross (14 net) development wells
- Construct new gas plant at Birch Mountain
- Install additional compression at Leismer, Kirby, Corn Lake and Woodenhouse

AXL Land
Co. Interest Gas Plant
Proposed New Gas Plant
Gas Pipelines

Lloydminster



Rob Kay
Completion/Workover Engineer

"During 1998 we conducted major oil workover programs at Swan Hills in Alberta and Eagle in British Columbia, but our oil workover activity will probably decline in 1999 due to low oil prices."

1998 Activity & Results

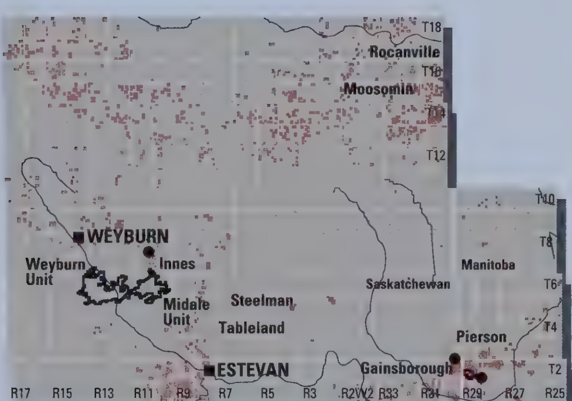
- Sales – 42 Mmcfd and 6,057 Bpd
- Acquired 8,896 net undeveloped acres
- Hold 202,200 net undeveloped acres in region
- Drilled 63 gross (47 net) wells, resulting in 15 gas, 37 oil and 11 dry
- Constructed first Saskatchewan gas plant at Edam
- Consolidated four gas plants with another area operator

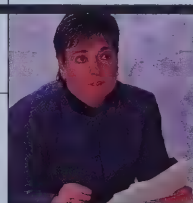
1999 Planned Activity

- Drill 15 gross (5 net) exploration wells and 3 gross (1 net) development wells
- Consolidate gas surface facilities with other area operators to reduce costs
- Continue improvement of heavy oil operating practices

AXL Land
New Gas Plant – 1998
Oil Pipelines
Co. Interest Gas Plant
Gas Pipelines

SE Saskatchewan and Manitoba





Sandy Drinnan
Manager, Land Negotiations

"Industry activity at Crown land sales declined in 1998 and we expect a further decline in 1999 if oil prices stay weak, but we will be active on a selective basis."

1998 Activity & Results

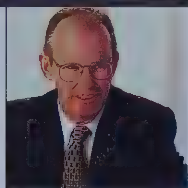
- Sales – 3,762 Bpd
- Acquired 4,419 net undeveloped acres
- Hold 246,900 net undeveloped acres in region
- Drilled 26 gross (19 net) wells, resulting in 1 gas, 22 oil and 3 dry
- Three successful 100% horizontal oil wells at Innes and Steelman

1999 Planned Activity

- Drill 1 gross (1 net) exploration well
- Potential for additional activity in this area, however, as it is exclusively an oil producing area, capital programs will probably be deferred due to low oil prices

AXL Land
Operated Oil Battery

7 Management's Discussion and Analysis



David Scobie
Senior Vice President & Chief Financial Officer (far left)

Darlene Wong
Manager of Finance

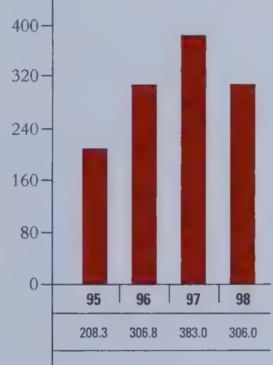
The following discussion and analysis of financial results should be read in conjunction with the consolidated financial statements for the year ended September 30, 1998 and is based on information available at November 19, 1998. Information provided herein for fiscal 1999 is based on assumptions regarding future events and actual results may vary from these estimates.

RESULTS OF OPERATIONS

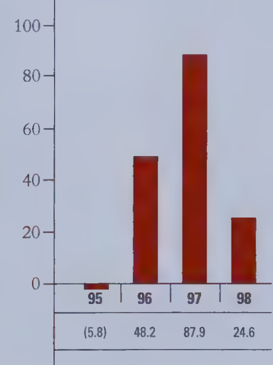
Overview

Anderson Exploration reported solid financial results in fiscal 1998 despite continued depressed oil prices. Stable gas prices, increased sales volumes and continued cost control allowed the Company to post respectable earnings and cash flow from operations in a difficult year. The Company spent $527.7 million on capital expenditures and finished the year with a debt to cash flow ratio of 2.3.

Consolidated Cash Flow from Operations
($ millions)



Consolidated Earnings
($ millions)



CASH FLOW FROM OPERATIONS AND EARNINGS
(in millions of dollars, except per share amounts)

	1998	*1997*
Cash flow from operations:		
Canadian oil and gas operations	*$ 296.3*	$ 369.9
Argentina oil and gas operations★	–	2.8
Total oil and gas operations	*296.3*	372.7
Pipeline operations	*9.7*	10.3
Cash flow from operations	*$ 306.0*	$ 383.0
Cash flow from operations per share	*$ 2.49*	$ 3.14
Earnings:		
Canadian oil and gas operations	*$ 17.9*	$ 74.7
Argentina oil and gas operations★	–	5.5
Total oil and gas operations	*17.9*	80.2
Pipeline operations	*6.7*	7.7
Earnings	*$ 24.6*	$ 87.9
Earnings per share	*$ 0.20*	$ 0.72

★ The Argentina operations were sold effective July 31, 1997, with the gain on sale being included in Argentina earnings in 1997.

CANADIAN OIL AND GAS OPERATIONS

In the following analysis, the components of revenue and expense are expressed on a barrel of oil equivalent basis, converting gas volumes to barrels of oil at 10 thousand cubic feet per barrel. This is a commonly used conversion ratio in the Canadian oil and gas industry and approximates historical relative sales values.[1]

[1] As supplemental information, several of these same operating statistics have been included in a table on pages 50 and 51 of this annual report converting gas volumes to barrels of oil at six thousand cubic feet per barrel. This conversion ratio approximates relative heating values and is commonly used outside of Canada, particularly in the United States.

Oil and Gas Revenues

Revenues from Canadian oil and gas operations decreased seven percent to $646.6 million in 1998 from $692.1 million in 1997. The decrease is due to a 12 percent decrease in product prices and lower revenues from straddle plant operations, offset by a seven percent increase in sales volumes and an increase in the amortization of natural gas contract settlement payments.

COMPONENTS OF CANADIAN OIL AND GAS REVENUES
(in million of dollars)

	1998		1997	
Natural gas sales	*$ 392.6*	*61%*	$ 381.9	55%
Crude oil sales	*201.6*	*31%*	242.4	35%
NGL sales	*44.7*	*7%*	52.4	8%
Crude oil hedging gains	*0.4*	*–*	3.5	–
Other*	*7.3*	*1%*	11.9	2%
	$ 646.6	*100%*	$ 692.1	100%

** Consists of straddle plant revenues, gains on brokered gas sales and amortization of natural gas contract settlement payments.*

Natural gas sales volumes increased to 555 million cubic feet per day in 1998 from 549 million cubic feet per day in 1997. New gas production came on stream in several areas, most notably in northeast British Columbia and the Peace River Arch, but this was offset to some extent by higher than expected decline rates in other areas. This, combined with some delays in bringing on new production and some disappointing drilling results, resulted in relatively flat gas sales in fiscal 1998. Natural gas sales are expected to increase to an average of 570 million cubic feet of gas per day in fiscal 1999.

The average price for natural gas increased two percent to $1.94 per thousand cubic feet in 1998 from $1.91 per thousand cubic feet in 1997. With normal winter temperatures, we expect gas prices to increase significantly in fiscal 1999, reflecting the reconnection to U.S. prices that will result from increased pipeline takeaway capacity. The Company is well positioned to take advantage of these price increases, with a significant portion of our natural gas sales portfolio linked to Alberta and British Columbia indices.

In 1998, approximately 64 percent of the Company's natural gas was sold directly to end users, marketing intermediaries and local distribution companies under contracts of varying terms. These contracts include both fixed and indexed pricing arrangements. The other 36 percent of the Company's natural gas was sold to supply aggregators. These aggregators in turn sell the gas to purchasers along gas pipelines generally at market sensitive prices. The proportion of natural gas sales sold to aggregators has decreased slightly from last year. It is expected that this trend will continue in the future.

NGL sales volumes increased 30 percent to 7,376 barrels per day in 1998 from 5,669 barrels per day in 1997, largely as a result of new liquids rich gas production in northeast British Columbia. The average price received decreased 34 percent to $16.61 per barrel in 1998 compared to $25.33 per barrel in 1997. The price for condensate, which is used to dilute heavy oil for pipeline transport, decreased dramatically through the year in concert with lower oil prices and as a result of decreased demand. In addition, propane prices have dropped through the year as demand has decreased and inventories have built up. The Company sells its NGL both as NGL mix and as individual components such as propane and butane in Alberta and Ontario markets. Sales prices are indexed to major NGL market centres, such as Edmonton, Alberta and Belvieu, Texas. NGL sales volumes are not expected to change significantly in fiscal 1999.

CANADIAN OIL AND GAS OPERATIONS

NATURAL GAS AND NGL NETBACKS
(per Mcf)*

	1998	1997
Sales revenue	*$ 1.91*	$ 1.96
Royalties	*(0.34)*	(0.33)
Operating costs	*(0.35)*	(0.31)
Netback	*$ 1.22*	$ 1.32
Royalty percentage	*18%*	17%
Daily sales volumes		
Natural gas (Mmcfd)	*555*	549
NGL (Bpd)	*7,376*	5,669

** NGL converted to natural gas at 1 bbl = 10 mcf.*

Crude oil sales volumes increased 14 percent to 29,808 barrels per day in 1998 from 26,170 barrels per day in 1997. The increase in volumes resulted in part from the acquisition of an additional 10 percent interest in Swan Hills Unit No. 1 at the beginning of the fiscal year and subsequent miscible flood expansion and workover programs in that area. The Company also conducted successful workover programs in northeast British Columbia and drilling programs in Saskatchewan. These increases were offset by the selective shut in of some heavy oil production due to low prices and production losses resulting from forest fires in the Swan Hills area north of Edmonton during the third quarter. Crude oil sales volumes in fiscal 1999 will be negatively affected by any cuts to the Company's capital program deemed necessary as a result of low oil prices.

World oil prices declined significantly through the fiscal year. In the first quarter, the Company's crude oil price averaged $22.52 per barrel. By the fourth quarter, it averaged $18.11 per barrel. Overall, the Company's average Canadian crude oil price for the year before hedging was $18.53 per barrel in 1998 compared to $25.37 in 1997, a decrease of 27 percent. Hedging gains, resulting from foreign currency swap agreements, increased the price to $18.57 in 1998 compared to $25.74 in 1997. All foreign currency swap agreements expired in December 1997.

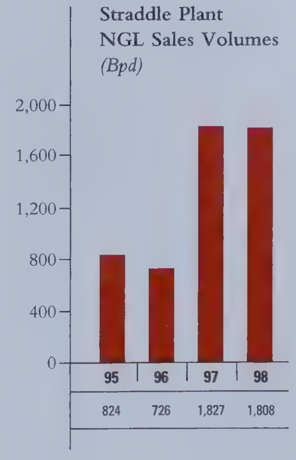
Price differentials between light and heavy crude oil widened over the course of the year, then narrowed near the end of fiscal 1998. The Company's average price for conventional oil was $19.80 per barrel and for heavy oil was $8.90 per barrel. The Company sold 3,476 barrels per day of heavy oil in fiscal 1998. Although heavy oil sales volumes have increased from 1997, the Company is still predominantly a light oil producer. In fiscal 1998, approximately 88 percent of crude oil sales were light or medium gravity oil. The average API gravity of the Company's crude oil stream at the end of fiscal 1998 was approximately 34 degrees.

CANADIAN OIL AND GAS OPERATIONS

CRUDE OIL NETBACKS
(per barrel)

	1998	1997
Sales revenue	*$ 18.53*	$ 25.37
Hedging gains	*0.04*	0.37
Royalties	*(2.92)*	(4.92)
Operating costs	*(7.26)*	(7.94)
Netback	*$ 8.39*	$ 12.88
Royalty percentage	*16%*	19%
Daily sales volumes (Bpd)	*29,808*	26,170

Other oil and gas revenue was $7.3 million in 1998 compared to $11.9 million in 1997. Revenues from straddle plant operations decreased by $5.5 million as the cost of feedstock gas increased and the prices for various NGL products decreased. This decrease was offset by an increase in the amortization of natural gas contract settlement payments. On June 30, 1998, the Company received settlement payments of $66.6 million related to the termination of certain long term natural gas sales contracts. The settlements were recorded as deferred revenue and are being recognized as revenue over the remaining periods of the original contracts.



Royalties

Canadian oil and gas royalties, net of the Alberta Royalty Tax Credit (ARTC), decreased nine percent to $107.7 million in 1998 from $117.9 million in 1997, consistent with the decrease in revenues. Royalties were 17 percent of oil and natural gas revenue in 1998, unchanged from 1997. In 1997, a $10.7 million reduction to Alberta gas Crown royalties was recorded as a result of final invoices received under the Alberta royalty simplification program related to 1994, 1995 and 1996. A further credit of $6.2 million was recorded in the fourth quarter of fiscal 1998 related to royalty simplification and other amendments. Without the refunds, royalties would have been 18 and 19 percent of revenue in 1998 and 1997, respectively. On a barrel equivalent basis, royalties decreased 15 percent to $3.18 in 1998 from $3.72 in 1997 primarily as a result of lower oil and NGL prices. ARTC was $1.4 million in 1998 compared to $1.2 million in 1997.

Royalties are sensitive to producing rates and, in Alberta, are based on reference prices established by the government. Royalty rates are expected to increase in fiscal 1999 as a result of increased natural gas prices. In fiscal 1998, the Company changed its accounting treatment for freehold mineral taxes. These costs have been reclassified from operating expense to royalty expense. All comparative periods have been restated.

Operating Expenses

Canadian oil and gas operating costs were $160.5 million in 1998 compared to $144.0 million in 1997. On a barrel equivalent basis, operating costs increased four percent to $4.75 in 1998 compared to $4.55 in 1997. Increased activity in the industry resulted in overall increases in the cost of services and equipment. In addition, the Company conducted significant workovers during the early part of the year. As a result of decreases in prices received for heavy oil production, a program to selectively shut in high cost heavy oil wells was instituted during the third quarter. Heavy oil operating costs on a per barrel basis decreased substantially in 1998. It is anticipated that 1999 overall operating expenses will be similar to 1998 on a barrel equivalent basis.

Other Revenue

Other revenue related to Canadian oil and gas operations was $9.4 million in 1998 compared to $9.1 million in 1997. In 1998, the Company realized a gain of $9.1 million on the sale of an interest in an oil sands lease. In 1997, the major components of other revenue were refund interest of $6.3 million related to prior year tax reassessments and a gain of $2.5 million on the sale of a portfolio investment.

General and Administrative Expenses

Canadian oil and gas general and administrative expenses were $31.6 million in 1998 compared to $26.7 million in 1997. On a barrel equivalent basis, general and administrative expenses increased 11 percent to $0.93 in 1998 compared to $0.84 in 1997. In 1997, general and administrative expenses included a $4.3 million non-cash recovery of pension costs that resulted from a settlement gain on the purchase of annuity contracts in respect of all retired and deferred vested members of the registered pension plan. On a cash basis, general and administrative expenses were $1.01 per barrel of oil equivalent in 1997. In 1998, increases in activity have resulted in higher staff levels and higher associated salary costs. These increases were offset by larger operator recoveries. The Company expects that 1999 general and administrative expenses per barrel of oil equivalent will increase as a result of lower recoveries on capital projects and higher staff costs.

CANADIAN OIL AND GAS OPERATIONS

GENERAL AND ADMINISTRATIVE EXPENSE
(in millions of dollars)

	1998	*1997*
Gross expense	*$ 50.5*	$ 42.1
Operator recoveries	*(18.9)*	(15.4)
Net expense	*$ 31.6*	$ 26.7

AVERAGE COST PER BARREL EQUIVALENT

	1998	*1997*
Gross expense	*$ 1.49*	$ 1.33
Operator recoveries	*(0.56)*	(0.49)
Net expense	*$ 0.93*	$ 0.84

The Company does not capitalize any general and administrative expenses, except to the extent of the Company's working interest in operated capital expenditure programs where overhead fees have been charged to third parties. The Company does not charge overhead fees on 100 percent owned projects. The Company also does not capitalize the salaries and other expenses of its exploration department as direct capital expenditures. This allows readers of the consolidated financial statements to assess the Company's true administrative expenditures. In fiscal 1998, the Company changed its accounting treatment with respect to certain field office costs not recoverable from partners. These costs have been reclassified from operating expenses to general and administrative expenses in order to match the costs with operator recoveries. All comparative periods have been restated.

Interest Expense

Interest expense related to Canadian oil and gas operations was $44.0 million in 1998 compared to $33.1 million in 1997. On a barrel equivalent basis, interest expense increased 24 percent to $1.30 in 1998 from $1.05 in 1997. The Company did not capitalize any interest related to its oil and gas operations in 1998 or 1997. The increase in interest expense was due to higher debt levels. Debt balances increased as a result of the Company's active drilling, construction and acquisitions program and its lower cash flow. Approximately 28 percent of the debt associated with oil and gas activities at September 30, 1998 was subject to floating interest rates. The average effective interest rate in fiscal 1998 was 6.8 percent. Interest expense is expected to increase slightly in fiscal 1999.

Current Taxes

Current taxes related to Canadian oil and gas operations were $6.7 million in 1998 compared to $1.8 million in 1997. On a barrel equivalent basis, these taxes were $0.20 in 1998 compared to $0.06 in 1997. Current taxes consist of the federal large corporations tax, provincial capital taxes and provincial resource surcharges. In 1997, a settlement was reached with Revenue Canada for prior year reassessments that related primarily to the calculation of resource allowance. A refund of $4.7 million reduced the Company's 1997 current tax provision. Canadian oil and gas operations are expected to pay some cash income taxes in 1999, in addition to paying the large corporations tax, provincial capital taxes and provincial resource surcharges.

The Company has approximately $829 million in unused tax pools related to its Canadian oil and gas operations. A portion of these tax pools are successored, as pools acquired in corporate acquisitions are generally dedicated to sheltering the income from properties held by an acquired company at the time of the acquisition.

Cash Flow From Operations

Cash flow from Canadian oil and gas operations was $296.3 million in 1998 compared to $369.9 million in 1997. On a barrel equivalent basis, this represents $8.76 in 1998 compared to $11.68 in 1997. The Company's cash flow is discretionary and available for capital programs and reduction of long term obligations.

CASH FLOW FROM CANADIAN OIL AND GAS OPERATIONS
($ per barrel equivalent)

	1998	1997
Oil and gas revenues	*$ 19.12*	$ 21.86
Royalties	*(3.18)*	(3.72)
Operating costs	*(4.75)*	(4.55)
	11.19	13.59
Other revenues	–	0.21
General and administrative expenditures	*(0.93)*	(1.01)
Interest	*(1.30)*	(1.05)
Current taxes	*(0.20)*	(0.06)
Cash flow from operations	*$ 8.76*	$ 11.68

Depletion and Depreciation

Depletion and depreciation provided on the unit of production method is based on total proven reserves with conversion of natural gas to oil using their relative energy content. The provision for depletion and depreciation on Canadian oil and gas properties increased eight percent to $252.8 million in 1998 compared to $234.4 million in 1997, consistent with increases in production. On a barrel equivalent basis, the provision was $7.48, a one percent increase from $7.40 in 1997. In 1999, depletion and depreciation expense and the rate per barrel of oil equivalent are expected to increase from 1998 as a result of the higher finding and development costs incurred this year.

Future Site Restoration

The Company provided $11.7 million for future site restoration related to its Canadian oil and gas operations in 1998 compared to $10.2 million in 1997. On a barrel equivalent basis, this charge amounted to $0.35 in 1998 and $0.32 in 1997. The future site restoration provision and the rate per barrel of oil equivalent will increase substantially in 1999 as a result of an increase in the Company's estimate of the future costs for well abandonments. At September 30, 1998, the estimate was increased by 80 percent over last year to reflect the higher costs associated with stricter environmental regulatory requirements and the actual costs of problem well abandonments.

Deferred Taxes

Deferred tax expense on Canadian oil and gas operations was $23.0 million or $0.68 per barrel of oil equivalent in 1998 compared to $58.4 million or $1.84 per barrel of oil equivalent in 1997. The total tax provision was $29.7 million in 1998 compared to $60.1 million in 1997. The total tax provision as a percentage of pre-tax earnings was 62.3 percent compared to 44.6 percent in 1997. The increase in the percentage is due to a decrease in the resource allowance claim compared to crown royalties and production taxes paid in the year. In addition, large corporations tax and provincial capital taxes and resource surcharges have a larger effect on the tax rate at lower levels of earnings. Finally, the 1997 tax rate percentage was reduced somewhat as a result of receipt of a tax refund related to prior year tax reassessments.

Earnings

Earnings from Canadian oil and gas operations were $17.9 million in 1998 compared to $74.7 million in 1997. On a barrel equivalent basis, earnings were $0.53 in 1998 compared to $2.36 in 1997. The decrease is attributable to lower liquids prices and increased expenses, partially offset by higher sales volumes. In addition, earnings in fiscal 1997 were increased by some one time items including a resource allowance tax reassessment and a non-cash pension recovery.

EARNINGS FROM CANADIAN OIL AND GAS OPERATIONS
($ per barrel equivalent)

	1998	1997
Cash flow from operations	*$ 8.76*	$ 11.68
Depletion and depreciation	*(7.48)*	(7.40)
Future site restoration	*(0.35)*	(0.32)
Deferred taxes	*(0.68)*	(1.84)
Other*	*0.28*	0.24
Earnings	*$ 0.53*	$ 2.36

* *Consists of gains on sale of assets and, in 1997, the non-cash pension recovery.*

ARGENTINA OIL AND GAS OPERATIONS

Effective July 31, 1997, the Company sold its investment in Home Oil International Ltd., a wholly owned subsidiary that conducted oil and gas exploration, development and production activities in Argentina. The contribution to the Company's fiscal 1997 annualized average crude oil sales was 1,302 barrels per day. Proceeds on the sale of the subsidiary were $50.4 million, net of selling costs. A gain of $8.0 million ($6.0 million after tax) was recorded on the sale in 1997. Cash flow from the Argentina operations was $2.8 million for the 10 months ended July 31, 1997.

PIPELINE OPERATIONS

The Company's pipeline transportation activities are conducted through its 50 percent interest in Federated Pipe Lines Ltd. The Company accounts for its interest in Federated using the proportionate consolidation method, whereby the Company's proportionate share of the assets, liabilities, revenues and expenses are included in its consolidated financial statements.

Cash flow from pipeline operations was $9.7 million in 1998 compared to $10.3 million in 1997. Earnings were $6.7 million in 1998 compared to $7.7 million in 1997. The decline in cash flow from operations and earnings is primarily due to higher interest expense and other administrative costs associated with the expansion. The Company's 50 percent share of daily average pipeline gatherings was 115,500 barrels per day in 1998 compared to 118,300 barrels per day in 1997.

Construction of the 280 mile extension to the pipeline system was completed in the fourth quarter of fiscal 1998. The system started up on August 27, 1998 and batch deliveries of ethane plus, condensate and crude oil to Edmonton and Fort Saskatchewan are currently being phased in. As demonstrated this year, the pipeline segment is less affected by the volatility of commodity prices and provides a stable source of cash flow from operations and earnings to the Company.

CAPITAL EXPENDITURES

Net capital expenditures were $527.7 million in 1998 compared to $468.7 million in 1997. The Company replaced 148 percent of its production with proven reserves, after revisions.

The Company completed several acquisitions of producing and exploratory properties during the year. The largest of these transactions involved the purchase of an additional 10.6 percent working interest in Swan Hills Unit No. 1 on October 6, 1997 for $98.8 million. The acquisition increased the Company's interest in this operated property to 30 percent. Construction costs associated with the Federated Pipe Lines expansion project were $44.5 million in 1998. The 1998 capital expenditure program was funded by cash flow from operations and increases in bank debt.

NET CAPITAL EXPENDITURES
(in millions of dollars)

	1998	1997
Exploration drilling and completion	*$ 80.0*	$ 71.5
Seismic	*15.4*	17.5
	95.4	89.0
Development drilling, completion and recompletion	*131.8*	111.1
Plant and production facilities	*108.9*	123.0
Miscible fluids	*5.7*	(0.9)
	246.4	233.2
Land acquisition and retention	*30.1*	47.3
Property acquisitions		
Swan Hills	*98.8*	–
Other	*24.6*	72.3
Argentina	*–*	6.0
Straddle plant	*2.4*	–
Pipeline	*51.5*	19.8
Corporate	*2.7*	3.5
Gross capital expenditures	*551.9*	471.1
Proceeds on disposition of properties*	*(24.2)*	(2.4)
Net capital expenditures	*$ 527.7*	$ 468.7

** Excludes the 1997 proceeds on sale of the Company's operations in Argentina.*

Net capital expenditures are currently budgeted to be $345 million in 1999, a decrease of 35 percent from 1998. Approximately 76 percent of this budget is targeted towards natural gas projects. As a result of recent decreases in oil prices, the Company is reviewing this budget and will be considering further cuts to ensure capital spending does not exceed available cash flow. Most of the cuts to capital spending will be directed to oil projects and will negatively impact oil sales levels and oil reserve additions.

FINDING AND DEVELOPMENT COSTS
(in millions of dollars)

	1998	1997
Net capital expenditures	*$527.7*	$468.7
Less pipeline and straddle plant expenditures	*(53.9)*	(19.8)
	473.8	448.9
Site restoration expenditures	*6.3*	3.8
Proceeds on sale of Argentina operations, net of working capital and other obligations	–	(47.1)
	$480.1	$405.6
Reserve additions before revisions (million barrels equivalent)		
Proven	*54.3*	51.2
Proven plus 1/2 probable	*64.8*	62.5
Reserve additions after revisions (million barrels equivalent)		
Proven	*49.9*	52.3
Proven plus 1/2 probable	*52.6*	60.4
Finding and development costs before revisions – current year ($ per barrel equivalent)		
Proven	*$ 8.84*	$ 7.92
Proven plus 1/2 probable	*$ 7.41*	$ 6.49
Finding and development costs after revisions – current year ($ per barrel equivalent)		
Proven	*$ 9.62*	$ 7.75
Proven plus 1/2 probable	*$ 9.12*	$ 6.71
Finding and development costs after revisions – three year average ($ per barrel equivalent)		
Proven	*$ 8.13*	
Proven plus 1/2 probable	*$ 7.66*	

Finding and development costs increased significantly over the prior year. Increased industry activity last winter resulted in an overall increase in the cost of services and equipment. Some of these cost pressures have since subsided. The Company also took some significant negative revisions, particularly to proven gas reserves. These revisions related to some negative drilling results at Kahntah, declining production performance at Mitsue and a detailed review of several miscellaneous properties. The drilling program at Kahntah was conducted in an attempt to improve poor production performance in relation to previously booked reserves. Medium to heavy probable oil reserves were also affected by poor pricing. Finding and development costs are budgeted to be closer to historic levels in fiscal 1999.

FINANCIAL RESOURCES AND LIQUIDITY

The Company's financial obligations increased by $161.4 million in fiscal 1998. Long term debt increased from $545.0 million at September 30, 1997 to $695.5 million at September 30, 1998 while the net working capital deficiency increased from $11.6 million to $22.5 million. The increase in financial obligations was due to net capital and site restoration expenditures in excess of cash flow from operations and other cash sources. Net capital expenditures of $527.7 million and site restoration expenditures of $6.3 million represented 174 percent of cash flow from operations. At the end of the third quarter, Anderson Exploration received settlement payments of $66.6 million related to the termination of certain long term gas sales contracts. These settlements were used to reduce long term debt. Proceeds of $12.0 million were received on the issue of common shares under the employee stock savings plan and stock option plan. At September 30, 1998, the Company had unused long term and operating lines of credit of $141.2 million. Sinking fund payments of $0.9 million are the only long term debt repayments required to be made in fiscal 1999 and this amount has been included in the working capital deficiency noted above.

SHARE PRICE

	1994	1995	1996	1997	1998				
	Year	Year	Year	Year	Q1	Q2	Q3	Q4	Year
High	18.00	16.25	15.25	20.25	*17.40*	*17.10*	*19.40*	*18.20*	***19.40***
Low	12.13	10.75	11.62	13.70	*12.85*	*12.50*	*15.05*	*12.60*	***12.50***
Close	15.38	12.63	13.70	17.20	*14.00*	*16.05*	*17.00*	*16.00*	***16.00***
Volume (000)	30,522	87,095	87,963	107,697	*31,877*	*30,651*	*23,714*	*14,053*	***100,295***

The Company uses interest rate swaps to effectively fix the interest rate on a significant portion of its outstanding debt. The swaps are described in the notes to the consolidated financial statements.

Cash flow from operations covered interest expense 7.6 times in 1998 compared to 11.7 times in 1997. Long term debt was 2.3 times 1998 cash flow from operations compared to 1.4 in 1997. In 1999, capital expenditures are expected to approximate cash flow from operations and the ratio of long term debt to cash flow from operations is expected to remain at just over 2.0.

SHARE INFORMATION

The Company's common shares were listed for trading on The Toronto Stock Exchange on July 12, 1988. At September 30, 1998, there were 123,260,352 common shares outstanding. During 1998, 899,389 common shares were issued for proceeds of $12.0 million under the employee stock option and stock savings plans. The Company's market capitalization at September 30, 1998 was $2.0 billion.

BUSINESS RISKS

Natural gas and crude oil exploration, production and marketing operations involve a number of business risks. These include the uncertainty of finding new reserves and the instability of commodity prices. These risks are compensated for by employing highly competent professional staff and utilizing equity and cash flow from operations to fund a significant portion of capital expenditures so that debt does not become a burden.

The Company generates its exploration prospects internally. Extensive geological, geophysical, engineering and environmental analyses are performed before committing to the drilling of new prospects. These analyses are used to ensure a suitable balance between risk and reward.

Commodity prices are influenced by supply and demand, both locally and worldwide, competition, the U.S. dollar exchange rate, transportation, political stability and seasonal changes in demand resulting from weather patterns in the Company's marketing areas. The value of the Canadian dollar, which is influenced by economic and political factors, affects all of the Company's crude oil sales and, in fiscal 1999, most of its natural gas sales. To reduce the impact of these factors, the Company maintains a balanced portfolio of sales contracts. Any hedging contracts are subject to approval by the Board of Directors. Anderson Exploration's current policy is that it will not hedge crude oil or natural gas prices. The Company does enter into physical contracts for the sale of natural gas at fixed prices and terms. It has also capped the heavy/light differential for heavy oil volumes at Edam, Saskatchewan under a marketing arrangement.

The Company has fixed the rate of interest on approximately 67 percent of its long term debt obligations. Between 1996 and 1998, the Company fixed the rate of interest on $253.0 million of its outstanding bank loans through swap agreements at an average rate of 6.84 percent. The agreements mature at various dates between 2001 and 2007. The Company has fixed the rate of interest on its $200.0 million oil indexed debentures at 8.26 percent to their maturity on October 31, 2000, also through the use of swap agreements. In addition, the Company, through its 50 percent ownership of Federated, has $11.7 million of sinking fund debentures outstanding which bear interest at a fixed rate of 9.54 percent.

Historically, regulatory issues and taxation have had a significant impact on the oil and gas industry. However, with the deregulation of the industry beginning in 1985 and stable taxation levels, there is currently a reasonable operating environment in Canada for financially healthy companies. The potential exists for this environment to change due to changes in taxation, energy and environmental policy.

The industry is subject to extensive regulations related to the protection of the environment. Environmental legislation in western Canada has undergone major revisions. Environmental standards and compliance are more stringent. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and has instituted a series of controls and procedures with respect to environmental protection. The estimated liability for future abandonment and restoration costs is reviewed annually and is recorded in accordance with CICA recommendations. Total future costs are currently estimated to be $276.2 million, of which $48.8 million has been recorded as a liability. This estimate is adjusted each year for recent experience and in the current year reflects rising costs associated with high industry activity levels and stricter environmental regulations. The Company is committed to managing this liability and will take full advantage of new technology during the drilling, producing and abandonment phases of its operations to keep these costs as low as possible.

SENSITIVITIES

The Company's earnings and cash flow from operations are highly sensitive to changes in factors that are beyond its control. An estimate of the Company's sensitivities to changes in commodity prices, exchange rates and interest rates is summarized below.

	Cash Flow from Operations		*Earnings*	
	$ millions	*$/share*	*$ millions*	*$/share*
Change of $0.10/Mcf in the price of natural gas	$16.0	$0.13	$ 9.7	$0.07
Change of $U.S. 1.00/bbl in the WTI crude oil price	$14.0	$0.11	$ 8.8	$0.07
Change of $U.S. 0.01 in the U.S./Canada exchange rate	$ 6.5	$0.05	$ 4.1	$0.04
Change of 1% in interest rates	$ 1.9	$0.02	$ 1.5	$0.02

YEAR 2000

Over a year ago, the Company began looking at its computer systems to assess the potential problems and costs associated with the year 2000 problem. The problem revolves around the fact that many computer systems and software applications have been designed to recognize dates using only the last two digits of the year. In the year 2000, it is anticipated that many systems and programs will not function properly. We have identified five major areas of vulnerability: 1) financial and technical systems, networks and data exchanges; 2) field production systems and processes; 3) pipeline control systems; 4) office security systems, telephone systems and equipment; and 5) exploration mapping. We are also vulnerable to third parties that we do business with, such as utility companies and product transportation companies. The Company has been systematically replacing major systems since 1996. A task force was formed in June 1997 to plan and implement procedures to prepare the Company for the year 2000. Senior management is involved in the process and receives monthly status reports on the project. The Board of Directors receives quarterly updates.

Inventories of computerized hardware and associated software have been completed. An assessment of the status of these items has been undertaken and detailed task plans have been prepared to schedule the testing and, where necessary, the upgrading or replacement of these items. Consulting firms have been employed to assist in project organization, assessment of embedded field systems and upgrading of pipeline equipment, and to provide a single source approach to major software vendors to the oil and gas industry. The Company is also actively involved in industry association committees and task forces. We have communicated with significant business associates to assess their awareness and preparedness for the year 2000 and are following up on responses from them. Testing of systems is in progress. Head office information systems have been substantially tested, with the remaining work expected to be completed by the end of calendar 1998. Field systems related to production and processing and pipeline control systems continue to be assessed. Scheduling of testing and replacement of non-compliant systems is ongoing and is expected to be completed by August 1999.

Costs associated with the project will be expensed or capitalized depending on their nature. These costs are not expected to have a material effect on the financial results of the Company.

While the Company has a comprehensive plan to deal with the year 2000 issue, it is not possible to be certain that all aspects of the problem will be fully resolved given the nature of the risks involved. This is particularly true with respect to the risks associated with the level of preparedness of our business associates. Effects of the year 2000 could range from minor errors to significant systems failures which affect the Company's ability to conduct normal business operations. The Company is developing formal contingency plans in the event that internal or third party problems occur.

BUSINESS PROSPECTS

Approximately 65 percent of the Company's remaining proven reserves are natural gas and natural gas liquids. The outlook for natural gas prices continues to be very good. Two new export pipeline expansion projects are scheduled to come on stream before the end of calendar 1998 and a new pipeline project has received regulatory approval and is projected to be in service by the end of the year 2000. As a result, gas prices are expected to increase significantly. The Company's natural gas sales portfolio has been structured to take advantage of these rising prices. The outlook for oil prices is uncertain. Conventional oil prices are not expected to show improvement early in 1999 and this may well be the case for the entire year. Increased demand for heavy oil and the narrowing of the differential between light and heavy oil prices indicates that heavy oil economics may improve during the year.

The Company's capital budget for fiscal 1999 is $345 million. The exploration strategy continues to shift towards higher risk/reward gas projects. With the recent softening in crude oil prices, the Company may make cuts to its capital budget and defer spending on oil projects until prices strengthen.

Last winter, the industry experienced significant increases in activity levels. This resulted in a shortage of services and higher costs, reflected in the higher operating expenses and finding and development costs reported throughout the industry in the last year. Industry activity has dropped off considerably in recent months due to low oil prices and some signs of lower costs are becoming apparent.

Low oil prices have taken their toll on the financial condition of many companies in the oil and gas industry. Anderson Exploration's weighting to natural gas and prudent management of its resources should allow the Company to take advantage of the opportunities that will surely surface in these less than buoyant times.

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Management's Report

Management is responsible for the preparation of the consolidated financial statements and the consistent presentation of all other financial information in this annual report.

Management maintains a system of internal controls to provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner.

External auditors, appointed by the shareholders, have examined the consolidated financial statements. Their report is presented below. The Audit Committee of the Board of Directors has reviewed the consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

J.C. Anderson

J.C. Anderson
Chairman & Chief Executive Officer
November 19, 1998

D.G. Scobie

David G. Scobie
Senior Vice President & Chief Financial Officer

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Anderson Exploration Ltd. as at September 30, 1998 and 1997 and the consolidated statements of earnings, retained earnings and changes in financial position for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at September 30, 1998 and 1997 and the results of its operations and the changes in its financial position for the years then ended in accordance with generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
November 19, 1998

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Consolidated Balance Sheets

September 30 *(stated in thousands of dollars)*	*1998*	*1997*
Assets		
Current assets		
Accounts receivable	*$ 101,381*	$ 129,797
Inventories	*9,753*	9,436
	111,134	139,233
Property, plant and equipment (note 2)	*2,445,129*	2,163,625
	$ 2,556,263	$ 2,302,858
Liabilities and Shareholders' Equity		
Current liabilities		
Bank indebtedness, unsecured	*$ 20,903*	$ 12,634
Accounts payable and accrued liabilities	*101,186*	133,364
Current portion of deferred revenue	*10,601*	3,935
Current portion of long term debt	*900*	900
	133,590	150,833
Long term debt (note 3)	*695,517*	544,982
Other credits (note 4)	*124,422*	64,399
Deferred income taxes	*580,018*	556,573
	1,533,547	1,316,787
Shareholders' equity		
Share capital (note 5)	*748,427*	736,388
Retained earnings	*274,289*	249,683
	1,022,716	986,071
	$ 2,556,263	$ 2,302,858

See accompanying notes to consolidated financial statements.

On behalf of the Board:

J.C. Anderson

Director

Director

Consolidated Statements of Earnings

Years ended September 30 (stated in thousands of dollars, except per share amounts)	1998	1997
Revenues		
Oil and gas	$ 646,585	$ 705,105
Royalties, net of ARTC of $1,372 (1997 - $1,227)	(107,716)	(120,391)
Pipeline	27,547	27,428
Other	9,529	17,514
	575,945	629,656
Expenses		
Operating	170,311	156,626
Depletion and depreciation	255,438	240,714
General and administrative	32,419	29,311
Interest (including $45,380 on long term debt; 1997 - $34,542)	46,133	35,954
Future site restoration	11,884	10,397
	516,185	473,002
Earnings before taxes	59,760	156,654
Taxes (note 7)		
Current	11,709	8,541
Deferred	23,445	60,170
	35,154	68,711
Earnings	$ 24,606	$ 87,943
Earnings per common share (note 6)		
Basic	$ 0.20	$ 0.72
Fully diluted	$ 0.20	$ 0.71
Weighted average number of common shares outstanding (thousands)	122,794	121,873

Consolidated Statements of Retained Earnings

Years ended September 30 (stated in thousands of dollars)	1998	1997
Retained earnings, beginning of year	$ 249,683	$ 161,740
Earnings	24,606	87,943
Retained earnings, end of year	$ 274,289	$ 249,683

See accompanying notes to consolidated financial statements.

Consolidated Statements of Changes in Financial Position

Years ended September 30 *(stated in thousands of dollars, except per share amounts)*	*1998*	*1997*
Cash provided by (used in):		
Operations		
Earnings	$ 24,606	$ 87,943
Add (deduct) non-cash items:		
Depletion and depreciation	255,438	240,714
Future site restoration	11,884	10,397
Deferred taxes	23,445	60,170
Gain on sale of assets (note 8)	(9,284)	(10,963)
Other	(52)	(5,216)
Cash flow from operations	306,037	383,045
Increase (decrease) in deferred revenue	61,156	(3,701)
Change in non-cash working capital related to operations	17,791	(17,480)
Change in other liabilities related to operations	–	(2,000)
	384,984	359,864
Investments		
Additions to property, plant and equipment	(551,891)	(471,153)
Proceeds on disposition of property, plant and equipment	24,233	2,409
Proceeds on sale of Home Oil International Ltd. (note 8)	–	50,417
Proceeds on sale of other investments (note 8)	–	5,323
Site restoration expenditures	(6,299)	(3,760)
Change in non-cash working capital related to investments	(21,870)	4,019
	(555,827)	(412,745)
Financing		
Increase in long term debt	150,535	32,215
Issue of common shares	12,039	16,806
	162,574	49,021
Decrease in cash	(8,269)	(3,860)
Cash (deficiency), beginning of year	(12,634)	(8,774)
Cash (deficiency), end of year	$ (20,903)	$ (12,634)
Cash flow from operations per common share (note 6):		
Basic	$ 2.49	$ 3.14
Fully diluted	$ 2.41	$ 3.04
Change in non-cash working capital:		
Accounts receivable	$ 28,416	$ (41,325)
Inventories	(317)	(1,720)
Accounts payable and accrued liabilities	(32,178)	33,021
Disposition of non-cash working capital	–	(3,437)
	$ (4,079)	$ (13,461)

Cash (deficiency) includes cash plus current bank indebtedness.

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Years ended September 30, 1998 and 1997
(tabular amounts in thousands of dollars, unless otherwise stated)

Anderson Exploration Ltd. ("Anderson Exploration" or "the Company") is engaged in the acquisition, exploration, development, production and pipeline transportation of oil and gas resources in western Canada. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada. Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

1. SIGNIFICANT ACCOUNTING POLICIES:

(a) Consolidation

The consolidated financial statements include the accounts of Anderson Exploration, its wholly owned subsidiaries and its 50 percent interest in Federated Pipe Lines Ltd. ("Federated"), a pipeline transportation company. The Company's interest in Federated is accounted for using the proportionate consolidation method, whereby the Company's proportionate share of the assets, liabilities, revenues and expenses are included in the consolidated financial statements.

(b) Joint interest operations

A significant proportion of the Company's oil and gas exploration, development and production activities are conducted with others and accordingly the accounts reflect only the Company's proportionate interest in such activities.

(c) Inventories

Inventories are stated at the lower of cost and net realizable value. Cost is determined using the specific item or average cost method.

(d) Property, plant and equipment

The Company follows the full cost method of accounting for oil and gas properties. Under this method, all costs relative to the exploration for and development of oil and gas reserves are capitalized into cost centres on a country by country basis. Capitalized costs include lease acquisitions, geological and geophysical costs, lease rentals on non-producing properties, costs of drilling productive and non-productive wells and plant and production equipment costs. General and administrative costs are not capitalized other than to the extent of the Company's working interest in operated capital expenditure programs to which overhead fees have been charged under standard industry operating agreements. Overhead fees are not charged on 100 percent owned projects. Proceeds received from disposals of conventional oil and gas properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

Depletion of oil and gas properties and depreciation of plant and production equipment are provided on the unit of production method based on total proven reserves before royalties as estimated by Company engineers. Natural gas sales and reserves are converted to equivalent units of crude oil using their relative energy content. Pipelines, buildings and other equipment are depreciated over their useful lives using the declining balance and straight line methods at rates varying from five percent to 40 percent per annum.

The Company applies a ceiling test to capitalized oil and gas property costs to ensure that such costs do not exceed the estimated future net revenues from production of proven reserves, at prices and operating costs in effect at the year end, plus the cost of unevaluated properties less management's estimate of impairment. The test also provides for estimated future administrative overhead, financing costs, future site restoration costs and taxes.

(e) Future site restoration costs

Provisions for future site restoration costs are made over the life of the Company's oil and gas properties using the unit of production method. Costs are based on engineering estimates considering current regulations, costs and industry standards. Actual expenditures incurred are applied against deferred future site restoration costs.

(f) Income taxes

The Company follows the tax allocation method of accounting for income taxes. Under this method, deferred income taxes are recorded to the extent that taxable income otherwise determined is adjusted by timing differences.

(g) Revenue recognition

Settlement payments received for restructuring or terminating long term natural gas sales contracts are recognized as revenue over the remaining period of the contracts or over the life of the reserves associated with the contracts.

(h) Foreign currency translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at year end while non-monetary assets and liabilities are translated at historical rates of exchange. Revenues and expenses are translated at monthly average rates of exchange. Translation gains and losses are included in earnings except for unrealized gains and losses on long term monetary items which are deferred and amortized to earnings over their remaining term.

(i) Hedging

Financial instruments are used to manage exposures related to interest rates and the Canada/U.S. exchange rate. They are not used for trading purposes.

Amounts received or paid under interest rate swaps are recognized in interest expense on an accrual basis, while gains and losses on exchange rate hedges are included in revenue on the sale of the related production.

(j) Comparative figures

Certain comparative figures have been restated to conform with the presentation adopted in the current year.

2. PROPERTY, PLANT AND EQUIPMENT:

	1998		1997	
	Cost	Accumulated depletion and depreciation	Cost	Accumulated depletion and depreciation
Oil and gas properties, including plant and production equipment	*$ 4,501,996*	*$ (2,179,349)*	$ 4,010,702	$ (1,919,474)
Pipelines	*150,774*	*(49,668)*	99,085	(47,037)
Buildings, land and other	*65,138*	*(43,762)*	60,093	(39,744)
	$ 4,717,908	*$ (2,272,779)*	$ 4,169,880	$ (2,006,255)
Net book value		*$ 2,445,129*		$ 2,163,625

At September 30, 1998, oil and gas properties included $157,000,000 (1997 – $141,500,000) relating to unproved properties which have been excluded from depletion and depreciation calculations. Future development costs of proven undeveloped reserves of $278,869,000 are included in depletion and depreciation calculations.

At September 30, 1998, the Company had a surplus in its ceiling test. The prices used in the ceiling test evaluation were as follows:

Natural gas (per thousand cubic feet)	$ 1.89
Crude oil and natural gas liquids (per barrel)	$ 17.00

3. LONG TERM DEBT:

	1998		1997	
	Balance Outstanding	Interest Rate[1]	Balance Outstanding	Interest Rate[1]
Bank loans	*$ 231,717*	*6.20%*	$ 133,282	4.07%
Bank loans subject to swaps	*253,000*	*6.68%*	200,000	6.77%
Oil indexed debentures, maturing October 2000	*200,000*	*8.26%*	200,000	8.26%
9.54% sinking fund debentures, maturing October 2002	*11,700*	*9.54%*	12,600	9.54%
	696,417		545,882	
Less current portion	*(900)*		(900)	
	$ 695,517		$ 544,982	

[1] As at September 30.

The Company has a $500,000,000 syndicated revolving credit facility with an extendible two year revolving period and a six year term period, a $65,000,000 syndicated revolving credit facility with an extendible five year maturity date and $62,500,000 in operating lines of credit. Advances under the facilities can be drawn in either Canadian or U.S. funds. The facilities bear interest at the bank's prime lending rate, U.S. labor rates plus applicable margins or bankers' acceptance rates plus stamping fees. The margins and stamping fees vary depending on financial statement ratios and can range from 0.35 percent to 0.75 percent. Loans under the facilities are unsecured.

The Company has fixed the rate of interest on $253,000,000 of its bank loans through swap agreements at an average rate of 6.84 percent. These agreements mature at various dates as shown below:

	Amount	*Interest Rate*[1]	*Maturity Date*
$	35,000	7.26%	September 2001
	32,500	6.56%	October 2001
	53,000[2]	5.95%	November 2001
	7,500	6.70%	October 2002
	40,000	7.22%	February 2007
	30,000	7.43%	March 2007
	30,000	7.22%	June 2007
	25,000	6.75%	July 2007
$	253,000	6.84%	

[1] Includes stamping fee.

[2] Entered into subsequent to September 30, 1998.

The oil indexed debentures bear interest at a fixed rate of 5.00 percent per annum plus a variable rate of up to 16.80 percent per annum based upon the average price of crude oil. The effective rate of interest on the debentures has been fixed to maturity at 8.26 percent by an unsecured interest rate swap agreement.

Long term debt maturities and sinking fund requirements for the next five years will be $900,000 in 1999, $900,000 in 2000, $263,353,000 in 2001, $84,233,000 in 2002 and $145,640,000 in 2003. It is anticipated that the bank loans will be extended and that the oil indexed debentures will be refinanced in 2001. If so, only $900,000 will actually be required to be funded in each of the next four years and $8,100,000 will be required to be funded in 2003.

The Company has unused operating lines of credit of $60,920,000.

4. OTHER CREDITS:

		1998		*1997*
Long term portion of deferred revenue	*$*	*70,016*	$	15,526
Deferred future site restoration costs		*48,759*		43,174
Pension accrual (note 9)		*5,647*		5,699
	$	*124,422*	$	64,399

On June 30, 1998, the Company received settlement payments of $66,631,000 related to the termination of certain long term natural gas sales contracts. The settlements were used to reduce long term debt and will be recognized as revenue over the remaining periods of the original contracts.

At September 30, 1998, the estimated future site restoration costs to be accrued over the life of the remaining reserves were $227,451,000.

5. SHARE CAPITAL:

Authorized:

Common shares: unlimited

Preferred shares: unlimited

Junior preferred shares, redeemable, participating: unlimited

Issued:

	1998			1997		
	Number of shares		*Amount (thousands)*	*Number of shares*		*Amount (thousands)*
Common shares						
Balance, beginning of year	*122,360,963*	*$*	*582,836*	121,025,087	$	566,030
Issued for cash on exercise of stock options	*694,207*		*8,869*	1,173,668		14,011
Issued for cash under employee stock savings plan	*205,182*		*3,170*	162,208		2,795
Balance, end of year	*123,260,352*		*594,875*	122,360,963		582,836
Contributed surplus			*153,552*			153,552
	123,260,352	*$*	*748,427*	122,360,963	$	736,388

At September 30, 1998, 8,170,185 common shares were reserved for issuance under the Company's employee stock option plan. Options to purchase 7,647,502 common shares for cash consideration of $10.60 to $17.80 per share were outstanding under the plan. The options are exercisable at various dates to the year 2005.

At September 30, 1998, 220,932 common shares were reserved for issuance under the Company's employee stock savings plan, issuable at market prices.

A shareholder protection rights plan was approved by the shareholders of the Company on February 14, 1996. If a bid to acquire control of the Company is made, the plan is designed to give the Board of Directors of the Company time to consider alternatives to allow shareholders to receive full and fair value for their shares. In the event that a bid, other than a permitted bid, is made, shareholders become entitled to exercise rights to acquire common shares of the Company at 50 percent of market value. This would significantly dilute the value of the bidder's holdings.

6. PER SHARE AMOUNTS:

Earnings per common share and cash flow from operations per common share are calculated using the weighted average number of common shares outstanding. The fully diluted cash flow from operations per common share calculations include imputed interest of $5,739,000 (1997 – $3,762,000) calculated at a rate of 5.40 percent (1997 – 4.75 percent) on the proceeds from the exercise of stock options. These amounts are tax effected at a rate of 44.8 percent to calculate fully diluted earnings per common share.

7. TAXES:

The provision for taxes differs from the result which would have been obtained by applying the combined federal and provincial tax rate to earnings before taxes. The difference results from the following items:

	1998	1997
Earnings before taxes	*$ 59,760*	$ 156,654
Combined federal and provincial tax rate	*44.8%*	44.8%
Computed "expected" tax	*$ 26,772*	$ 70,181
Increase (decrease) in taxes resulting from:		
Royalties and other payments to provincial governments	*42,108*	45,914
Non-deductible depletion	*2,194*	2,288
Resource allowance	*(38,967)*	(46,793)
Income tax rebates and credits	*(2,715)*	(1,935)
Capital taxes	*6,951*	6,318
Resource allowance settlement	–	(4,680)
Non-taxable capital gains	–	(1,008)
Other	*(1,189)*	(1,574)
Provision for taxes	*$ 35,154*	$ 68,711

Property, plant and equipment with a net book value of $37,277,000 (1997 – $41,286,000) has no cost base for income tax purposes.

In 1997, the Company recorded a settlement payment from Revenue Canada relating to reassessments of the 1982 to 1992 tax years of certain subsidiaries of the Company. The most significant issue in the reassessments related to the methodology used to calculate resource allowance. A tax refund of $4,680,000 and refund interest of $6,320,000 were received.

8. SALE OF ASSETS:

(a) Athabasca Oil Sands Lease

Effective June 12, 1998, the Company sold its interest in an Athabasca oil sands lease for proceeds of $9,331,000. A gain of $9,132,000 ($5,139,000 after tax) was recorded on the sale of this property.

(b) Home Oil International Ltd.

Effective July 31, 1997, the Company sold its investment in Home Oil International Ltd., a wholly owned subsidiary that conducted oil and gas exploration, development and production activities in Argentina. Proceeds were $50,417,000, net of selling costs and cash sold. A gain of $8,007,000 ($6,008,000 after tax) was recorded on the sale of this investment.

(c) Discovery Petroleum N.L.

Effective December 20, 1996, the Company sold its portfolio investment in the shares of Discovery Petroleum N.L. for proceeds of $5,323,000. A gain of $2,540,000 ($1,760,000 after tax) was recorded on the sale of this investment.

9. PENSION PLANS:

The Company has a non-contributory registered defined benefit pension plan. In June 1995, the plan was amended to give active employees an opportunity to opt out of the plan in favour of a defined contribution alternative. Most employees opted out of the plan. These employees and all new employees accrue future benefits based on defined contributions. Employees remaining in the plan continue to accrue benefits under the defined benefit plan. The plan is funded based on independent actuarial valuations. Plan assets are invested primarily in publicly traded equity and fixed income securities. Retirement benefits are based on the employees' years of credited service and salaries during the last years of employment.

The retirement benefit under the registered plan is subject to a maximum pension as determined under the Income Tax Act (Canada). To the extent this limitation applied, supplemental retirement allowances were provided to qualifying employees at the time so that the total retirement benefits were sufficient to provide the annuity that those employees would have been entitled to without the limitation. To support the Company's obligations under the supplemental plan, the Company has issued a letter of credit to the custodian of the supplemental plan.

In August 1997, the Company purchased annuity contracts in respect of all retired and deferred vested members of the registered plan. Pension assets were used to purchase the annuities. Projected benefit obligations were reduced to reflect this purchase of annuities.

Based on an actuarial valuation dated October 1, 1996, adjusted for the purchase of the annuities, the status of the plans at September 30, 1998 was:

	1998	*1997*
Pension plan assets	***$ 19,466***	$ 18,812
Projected benefit obligations	***(7,665)***	(7,385)
Excess of pension plan assets over projected benefit obligations	***$ 11,801***	$ 11,427

In 1998, the Company recorded pension expense of $404,000. In 1997, the Company recorded a pension recovery of $4,347,000 from the amortization of experience gains and a settlement gain on the purchase of annuity contracts in respect of all retired and deferred vested members of the registered pension plan.

10. FINANCIAL INSTRUMENTS:

(a) Interest rate risk

The Company has entered into fixed rate debt agreements and interest rate swap agreements in order to manage its interest rate exposure on debt instruments. These agreements are described in note 3.

(b) Foreign currency exchange risk

The Company is exposed to foreign currency fluctuations as crude oil and a portion of natural gas prices received are referenced to U.S. dollar denominated prices.

(c) Credit risk

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

The Company is also exposed to credit risk associated with possible non-performance by counterparties to the interest rate swap agreements. The Company believes these risks to be minimal as the counterparties are major financial institutions which have at least an AA credit rating as determined by recognized credit rating agencies.

(d) Fair value of financial instruments

The carrying amounts of financial instruments included in the consolidated balance sheet, other than long term debt, approximate their fair value due to their short term maturity.

The estimated fair values of long term debt and derivative instruments have been determined based on discounted cash flow analysis using current market interest rates for financial instruments with similar maturities.

The carrying values and estimated fair values of long term debt and derivative instruments are as follows:

	1998		*1997*	
	Carrying Value	*Fair Value*	*Carrying Value*	*Fair Value*
Bank loans	*$ (484,717)*	*$ (484,717)*	$ (333,282)	$ (333,282)
Interest rate swaps on bank loans	*$ –*	*$ (11,703)*	$ –	$ (7,901)
Oil indexed debentures	*$ (200,000)*	*$ (198,602)*	$ (200,000)	$ (198,327)
Interest rate swap on oil indexed debentures	*$ –*	*$ (12,070)*	$ –	$ (17,893)
9.54% sinking fund debentures	*$ (11,700)*	*$ (13,103)*	$ (12,600)	$ (14,276)

11. SEGMENTED INFORMATION:

The Company operates in Canada in the oil and gas and pipeline transportation industries.

1998	*Oil and Gas*	*Pipeline*	*Total*
Revenues, net of royalties	*$ 548,233*	*$ 27,712*	*$ 575,945*
Operating expenses	*(160,471)*	*(9,840)*	*(170,311)*
Depletion, depreciation and site restoration	*(264,551)*	*(2,771)*	*(267,322)*
General and administrative expenses	*(31,576)*	*(843)*	*(32,419)*
Interest	*(43,983)*	*(2,150)*	*(46,133)*
Earnings before taxes	*47,652*	*12,108*	*59,760*
Taxes	*(29,704)*	*(5,450)*	*(35,154)*
Earnings	*$ 17,948*	*$ 6,658*	*$ 24,606*
Cash flow from operations	*$ 296,313*	*$ 9,724*	*$ 306,037*
Net capital expenditures	*$ 476,167*	*$ 51,491*	*$ 527,658*
Total assets	*$ 2,451,328*	*$ 104,935*	*$ 2,556,263*

1997	Oil and Gas	Pipeline	Total
Revenues, net of royalties	$ 601,797	$ 27,859	$ 629,656
Operating expenses	(147,753)	(8,873)	(156,626)
Depletion, depreciation and site restoration	(247,733)	(3,378)	(251,111)
General and administrative expenses	(28,701)	(610)	(29,311)
Interest	(34,811)	(1,143)	(35,954)
Earnings before taxes	142,799	13,855	156,654
Taxes	(62,513)	(6,198)	(68,711)
Earnings	$ 80,286	$ 7,657	$ 87,943
Cash flow from operations	$ 372,699	$ 10,346	$ 383,045
Net capital expenditures	$ 448,941	$ 19,803	$ 468,744
Total assets	$ 2,245,495	$ 57,363	$ 2,302,858

12. UNCERTAINTY DUE TO THE YEAR 2000 ISSUE:

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000 and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect an entity's ability to conduct normal business operations. While the Company has a plan to address the Year 2000 Issue, it is not possible to be certain that all aspects of the issue affecting the Company, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.

10 | Quarterly Review

Year ended September 30, 1998 *($ millions, except per share amounts)*	*Q1*	*Q2*	*Q3*	*Q4*	*Total*
Revenue before royalties	*$ 195.2*	*$ 163.5*	*$ 164.1*	*$ 160.9*	***$ 683.7***
Cash flow from operations	*$ 90.8*	*$ 65.1*	*$ 67.7*	*$ 82.4*	***$ 306.0***
Cash flow from operations per common share	*$ 0.74*	*$ 0.53*	*$ 0.55*	*$ 0.67*	***$ 2.49***
Earnings	*$ 11.3*	*$ (2.6)*	*$ 5.7*	*$ 10.2*	***$ 24.6***
Earnings per common share	*$ 0.09*	*$ (0.02)*	*$ 0.05*	*$ 0.08*	***$ 0.20***
Net capital expenditures	*$ 214.7*	*$ 159.6*	*$ 95.2*	*$ 58.2*	***$ 527.7***
Daily sales					
Gas (Mmcfd)	*561*	*554*	*545*	*558*	***555***
Oil (Bpd)	*30,700*	*31,062*	*29,046*	*28,441*	***29,808***
NGL (Bpd)	*6,529*	*8,731*	*6,948*	*7,320*	***7,376***
	37,229	*39,793*	*35,994*	*35,761*	***37,184***

Year ended September 30, 1997 *($ millions, except per share amounts)*	*Q1*	*Q2*	*Q3*	*Q4*	*Total*
Revenue before royalties	$ 207.1	$ 199.6	$ 159.9	$ 183.4	$ 750.0
Cash flow from operations	$ 119.3	$ 102.5	$ 76.5	$ 84.7	$ 383.0
Cash flow from operations per common share	$ 0.98	$ 0.84	$ 0.63	$ 0.69	$ 3.14
Earnings	$ 37.2	$ 23.2	$ 8.4	$ 19.1	$ 87.9
Earnings per common share	$ 0.31	$ 0.19	$ 0.07	$ 0.15	$ 0.72
Net capital expenditures	$ 72.2	$ 174.9	$ 97.2	$ 124.4	$ 468.7
Daily sales					
Gas (Mmcfd)	542	543	563	548	549
Oil (Bpd)	26,464	27,834	27,063	28,528	27,472
NGL (Bpd)	6,701	5,752	5,023	5,197	5,669
	33,165	33,586	32,086	33,725	33,141

11 Ten Year Review

	1998	1997	1996	1995 (pooled)*
Financial				
(in millions, except per share amounts)				
Revenues				
Oil and gas	$ 646.6	$ 705.1	$ 569.3	$ 518.4
Royalties, net of ARTC	(107.7)	(120.4)	(92.6)	(85.6)
Pipeline	27.5	27.4	28.0	26.8
Other	9.5	17.5	3.3	3.4
	575.9	629.6	508.0	463.0
Expenses				
Operating	170.3	156.6	115.0	111.9
Depletion and depreciation	255.4	240.7	219.6	209.0
General and administrative	32.4	29.3	28.0	50.4
Interest	46.1	36.0	41.4	49.6
Future site restoration	11.9	10.4	10.0	8.4
Restructuring costs	–	–	–	36.9
	516.1	473.0	414.0	466.2
Earnings (loss) before taxes	59.8	156.6	94.0	(3.2)
Taxes				
Current	11.7	8.5	12.3	6.8
Deferred	23.5	60.2	33.5	(4.2)
	35.2	68.7	45.8	2.6
Earnings (loss)	$ 24.6	$ 87.9	$ 48.2	$ (5.8)
Per common share	$ 0.20	$ 0.72	$ 0.40	$ (0.05)
Cash flow from operations	$ 306.0	$ 383.0	$ 306.8	$ 208.3
Per common share	$ 2.49	$ 3.14	$ 2.54	$ 1.73
Balance sheet information				
Net additions to property, plant and equipment	$ 527.7	$ 468.7	$ 247.4	$ 322.5
Corporate acquisitions (dispositions)	$ –	$ (50.4)	$ –	$ –
Long term debt	$ 695.5	$ 545.0	$ 512.7	$ 561.9
Working capital (deficiency)	$ (22.5)	$ (11.6)	$ (18.0)	$ (24.5)
Shareholders' equity	$ 1,022.7	$ 986.1	$ 881.3	$ 828.0
Common shares outstanding at September 30	123.3	122.4	121.0	120.5
Operating				
Daily sales				
Natural gas (Mmcfd)	555	549	506	507
Oil (Bpd)	29,808	27,472	24,097	25,628
NGL (Bpd)	7,376	5,669	5,489	6,253
	37,184	33,141	29,586	31,881
Proven reserves				
Natural gas (Bcf)	1,758	1,768	1,798	1,812
Oil and NGL (Mmbbls)	148.0	130.9	107.7	99.2
Proven plus probable reserves				
Natural gas (Bcf)	2,675	2,713	2,694	2,739
Oil and NGL (Mmbbls)	225.6	200.3	165.7	158.9
Wells drilled for oil and gas				
Gross	446	669	335	308
Net	280	426	210	230
Employees				
Calgary	390	347	293	314
Field	347	332	329	347

*1995**	*1994**	*1993**	*1992**	*1991**	*1990**	*1989**
$ 230.0	$ 209.0	$ 136.6	$ 94.7	$ 93.6	$ 82.7	$ 66.3
(39.2)	(42.9)	(26.1)	(18.1)	(20.8)	(15.0)	(13.1)
–	–	–	–	–	–	–
–	0.1	0.1	0.1	–	6.1	3.9
190.8	166.2	110.6	76.7	72.8	73.8	57.1
42.1	35.2	24.4	20.5	18.6	14.5	9.5
93.2	66.7	42.7	30.5	23.7	19.8	15.1
9.8	8.0	6.2	5.6	4.6	3.5	2.7
13.7	8.3	10.0	10.8	8.3	11.3	10.5
4.4	3.3	2.0	1.5	–	–	–
4.1	–	–	–	–	–	–
167.3	121.5	85.3	68.9	55.2	49.1	37.8
23.5	44.7	25.3	7.8	17.6	24.7	19.3
2.2	1.9	0.9	0.8	5.0	0.9	0.4
9.6	18.6	9.4	3.8	6.6	10.6	7.9
11.8	20.5	10.3	4.6	11.6	11.5	8.3
$ 11.7	$ 24.2	$ 15.0	$ 3.2	$ 6.0	$ 13.2	$ 11.0
$ 0.21	$ 0.45	$ 0.33	$ 0.08	$ 0.15	$ 0.36	$ 0.31
$ 119.0	$ 112.8	$ 69.0	$ 39.1	$ 36.3	$ 38.2	$ 31.0
$ 2.09	$ 2.09	$ 1.52	$ 0.95	$ 0.89	$ 1.04	$ 0.86
$ 175.6	$ 178.9	$ 81.6	$ 12.5	$ 33.0	$ 72.5	$ 32.3
$ –	$ 70.0	$ –	$ 106.5	$ –	$ –	$ –
$ 153.3	$ 90.5	$ 90.8	$ 152.2	$ 72.7	$ 75.0	$ 80.0
$ (16.3)	$ (20.4)	$ (12.1)	$ 1.5	$ 1.6	$ 3.4	$ 0.3
$ 421.5	$ 410.7	$ 276.1	$ 196.3	$ 191.8	$ 182.7	$ 131.0
57.2	56.9	49.4	41.4	41.2	40.6	36.2
282	215	160	111	77	66	71
8,606	6,510	4,775	4,131	4,346	3,821	1,636
2,040	1,746	1,182	1,617	1,082	1,162	1,155
10,646	8,256	5,957	5,748	5,428	4,983	2,791
901	900	755	698	619	575	556
30.4	29.4	19.4	17.7	15.1	16.4	15.3
1,387	1,378	1,162	1,033	907	872	810
46.7	43.9	28.4	25.4	22.3	24.0	23.8
136	225	157	43	73	105	77
105	172	90	21	54	77	49
105	106	79	65	53	52	42
119	110	79	67	61	53	44

** In September 1995, a business combination between Anderson Exploration Ltd. and Home Oil Company Limited was accomplished. The business combination was accounted for using the pooling of interests method of accounting. Under this method, the consolidated financial and operating results reflect the historical results of both companies as if they had always been together. This means that the pooled financial and operating results for fiscal 1995 reflect the combined operations of the two companies for that entire year even though the business combination was only accomplished in the last month of the year. Fiscal 1998 is the third full year after the business combination. Historical results of Anderson Exploration Ltd. on a stand alone basis have been provided as supplementary information for 1995 and prior years.*

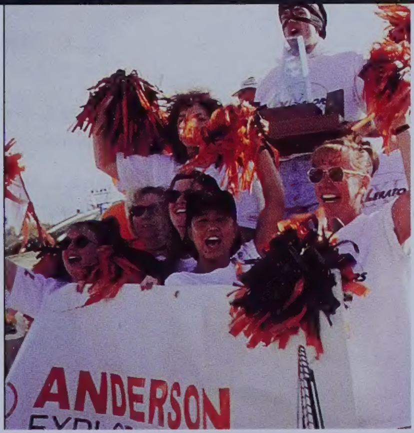
12 Supplementary Information

	Gas Converted to Oil at 10 Mcf/Bbl*			Gas Converted to Oil at 6 Mcf/Bbl*		
	1998	*1997*	*1996*	*1998*	*1997*	*1996*
Canadian Oil and Gas Operations						
Cash Flow from Operations and Earnings per Barrel of Oil Equivalent						
Oil and gas revenues	***$ 19.12***	$ 21.86	$ 19.26	***$ 13.67***	$ 15.37	$ 13.48
Royalties	***(3.18)***	(3.72)	(3.12)	***(2.28)***	(2.62)	(2.19)
Operating costs	***(4.75)***	(4.55)	(3.52)	***(3.39)***	(3.20)	(2.46)
	11.19	13.59	12.62	***8.00***	9.55	8.83
Other revenues	***–***	0.21	0.03	***0.01***	0.15	0.02
General and administrative expenditures	***(0.93)***	(1.01)	(0.95)	***(0.67)***	(0.71)	(0.66)
Interest	***(1.30)***	(1.05)	(1.38)	***(0.93)***	(0.74)	(0.97)
Current taxes	***(0.20)***	(0.06)	(0.19)	***(0.14)***	(0.04)	(0.14)
Cash flow from operations	***8.76***	11.68	10.13	***6.27***	8.21	7.08
Depletion and depreciation	***(7.48)***	(7.40)	(7.37)	***(5.35)***	(5.21)	(5.16)
Future site restoration	***(0.35)***	(0.32)	(0.34)	***(0.25)***	(0.23)	(0.24)
Deferred taxes	***(0.68)***	(1.84)	(1.18)	***(0.49)***	(1.30)	(0.82)
Other	***0.28***	0.24	0.16	***0.19***	0.17	0.11
Earnings	***$ 0.53***	$ 2.36	$ 1.40	***$ 0.37***	$ 1.64	$ 0.97
Average daily sales in barrels of oil equivalent	***92,634***	86,739	78,658	***129,599***	123,339	112,398
Natural Gas and NGL Netbacks						
Average sales price ($ per Mcf)	***$ 1.91***	$ 1.96	$ 1.63	***$ 2.00***	$ 2.04	$ 1.69
Royalty expense ($ per Mcf)	***(0.34)***	(0.33)	(0.25)	***(0.35)***	(0.34)	(0.26)
Operating expense ($ per Mcf)	***(0.35)***	(0.31)	(0.26)	***(0.37)***	(0.32)	(0.27)
Cash netback	***$ 1.22***	$ 1.32	$ 1.12	***$ 1.28***	$ 1.38	$ 1.16
Average daily natural gas sales (Mmcfd)	***555***	549	506	***555***	549	506
Average daily NGL sales (Bpd)	***7,376***	5,669	5,489	***7,376***	5,669	5,489
Crude Oil Netbacks						
Average sales price ($ per barrel)	***$ 18.57***	$ 25.74	$ 25.68			
Royalty expense ($ per barrel)	***(2.92)***	(4.92)	(4.75)			
Operating expense ($ per barrel)	***(7.26)***	(7.94)	(5.72)			
Cash netback	***$ 8.39***	$ 12.88	$ 15.21			
Average daily crude oil sales (Bpd)	***29,808***	26,170	22,560			

	Gas Converted to Oil at 10 Mcf/Bbl*						Gas Converted to Oil at 6 Mcf/Bbl*					
	1998		1997		1996		1998		1997		1996	
Finding and Development Costs												
Current year additions before revisions												
Proven	***$***	***8.84***	$	7.92	$	6.74	***$***	***6.80***	$	6.28	$	4.97
Proven plus one half probable	***$***	***7.41***	$	6.49	$	5.67	***$***	***5.74***	$	5.11	$	4.14
Current year additions after revisions												
Proven	***$***	***9.62***	$	7.75	$	6.63	***$***	***7.66***	$	6.37	$	5.05
Proven plus one half probable	***$***	***9.12***	$	6.71	$	7.09	***$***	***7.44***	$	5.52	$	5.44
Three year weighted average after revisions												
Proven	***$***	***8.13***					***$***	***6.47***				
Proven plus one half probable	***$***	***7.66***					***$***	***6.18***				

**The operating statistics presented in this analysis are expressed on a barrel of oil equivalent basis (or thousand cubic feet equivalent basis), using two different conversion ratios. In Canada, it is common to convert gas to oil at 10 thousand cubic feet per barrel which approximates historical relative sales value. Outside of Canada, particularly in the United States, it is more common to convert gas to oil at six thousand cubic feet per barrel, which approximates relative heating values.*

Calgary Corporate Challenge "Outstanding Team Spirit"



This year, Anderson Exploration was selected as a participant in the annual Calgary Corporate Challenge for the first time. These games are organized to promote company spirit through participation in various sporting events and social functions. Over 150 Calgary companies compete in the games. Anderson Exploration was awarded the "Overall Outstanding Spirit of the Games Award" for displaying the most Company pride and sportsmanship during the games. The "AXLerators" also did well on the athletic front winning a gold medal in squash and a bronze medal in darts. Congratulations to the large number of our employees that participated.

13 Corporate Information

BOARD OF DIRECTORS

J.C. Anderson
(1968)
Chairman &
Chief Executive Officer
Calgary, Alberta

Ian D. Bayer +
(1984)
President &
Chief Executive Officer
Battle Mountain Gold Company
Houston, Texas

W. Gordon Brown, Q.C. ‡
(1982)
Partner
Bennett Jones
Calgary, Alberta

Noel A. Cleland
(1995)
Corporate Director
Calgary, Alberta

E. Susan Evans, Q.C. +
(1995)
Corporate Director
Calgary, Alberta

J. Richard Harris ‡
(1988)
Oil & Gas Consultant
Calgary, Alberta

Charles J. Howard +
(1993)
President &
Chief Executive Officer
Ausnoram Holdings Limited
Toronto, Ontario

Larry J. Macdonald
(1992)
President &
Chief Operating Officer
Calgary, Alberta

John H. Morrish
(1995)
Corporate Director
Surrey, British Columbia

CORPORATE OFFICERS

J. C. Anderson
Chairman &
Chief Executive Officer

Larry J. Macdonald
President &
Chief Operating Officer

David G. Scobie
Senior Vice President &
Chief Financial Officer
Secretary-Treasurer

Alan D. Archibald
Vice President, Operations

Henry H. Assen
Vice President, Marketing

Fred E. Baker
Vice President, Exploration

Brian H. Dau
Vice President, Exploitation
& Business Development

Dan F. Kell
Vice President, Land

Richard C. Osborne
Vice President, Pipelines

Gerald S. Read
Controller

MANAGERS

Area Exploitation

Scot Collins
Phil A. Harvey
Greg J. Kuran
Kevin L. Stashin
Geoff G. Zakaib

Area Exploration

Steve J. Babcock
Frank J. Gratton
Ron A. Lambie
Al J. Onia
Tim B. Watters

Business Development

Sam A. Coles

Facilities

W. A. (Drew) Livingston

Finance

Linda M. Ellergodt
(Office Services)

George R. Nichols
(Operations Accounting)

M. Darlene Wong
(Finance)

Land

Sandy M. Drinnan
(Land Negotiations)

Lynn M. Gregory
(Administration)

Marketing

Keith J. Fardy
(Natural Gas)

Josie M. MacGillivray
(Liquids)

Operations

Carl F. Hiscock
(Drilling)

Jan H. Olthof
(Production)

Jim N. Peta
(Completions)

Walter C. Tersmette
(Safety & Environment)

Pipelines

Chris I. Grayston
(Shipper Services & Accounting)

Burdette M. Lehne
(Operations)

District Superintendents

Terry J. Clelland
Swan Hills, AB

J. Rob Cursons
Carstairs, AB

Tip C. Johnson
Fort St. John, B.C.

Doug J. Moore
Lloydminster, AB

Ron L. Strandquist
Fairview, AB

+ Member of Audit Committee

‡ Member of Compensation & Nominating Committee
(Fiscal year first elected as Director)

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Field Offices
Carstairs, Alberta
Fairview, Alberta
Fort St. John, B.C.
Lloydminster, Alberta
Swan Hills, Alberta

Auditors
KPMG LLP
Calgary, Alberta

Solicitors
Bennett Jones
Calgary, Alberta

Independent Engineers
Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

Registrar & Transfer Agent
Montreal Trust Company of Canada
Calgary, Vancouver, Regina, Winnipeg, Toronto, Montreal, Halifax

Stock Exchange
The Toronto Stock Exchange
Symbol: AXL

Annual Information Form
Copies of the Company's Annual Information Form are available on request.

Corporate Governance
Information concerning the Company's corporate governance is presented in the Notice of and Information Circular for the Annual General and Special Meeting of Shareholders dated December 28, 1998.

CONVERSION AND OTHER INFORMATION

Volume Reporting
All production, sales and reserve statistics are Anderson Exploration's working interest amounts before deduction of royalties, unless stated otherwise. Where volumes are reported in barrels of oil equivalent, gas is converted to oil at 10 thousand cubic feet per barrel unless otherwise noted. This is a commonly used conversion ratio in the Canadian oil and gas industry and approximates historical relative sales values. As supplemental information, several of these same operating statistics have been included in a table on pages 50 and 51 of this annual report converting gas volumes to barrels of oil at six thousand cubic feet per barrel. This conversion ratio approximates relative heating values and is commonly used outside of Canada, particularly in the United States.

Financial Reporting
All amounts are in Canadian dollars, unless stated otherwise. The Company's fiscal year end is September 30.

Metric Conversion
The petroleum industry in Canada has officially converted to the International System of Units for measuring and reporting. The table at the bottom of this page notes conversion factors relevant to this report.

To Convert From	To	Divide by
Thousand cubic feet (Mcf) gas	Thousand cubic metres (10^3m^3)	35.4937
Barrels (Bbls) oil	Cubic metres (m^3)	6.2898
Feet (well depths)	Metres (m)	3.2808
Miles (distance)	Kilometres (km)	0.6214
Acres (land)	Hectares (ha)	2.5000

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